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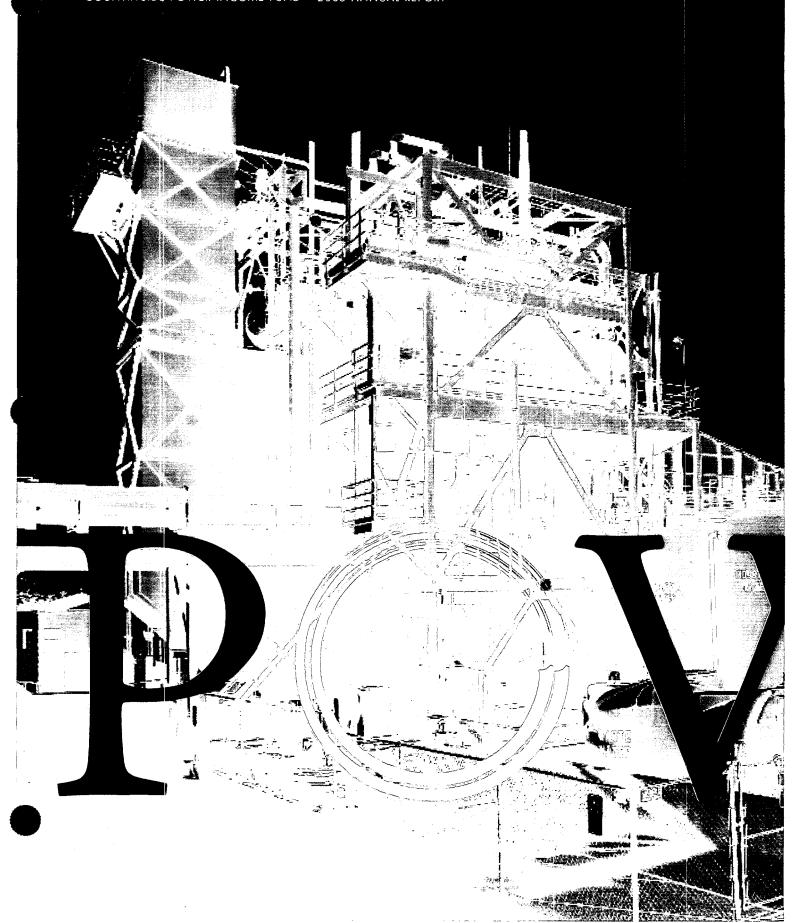
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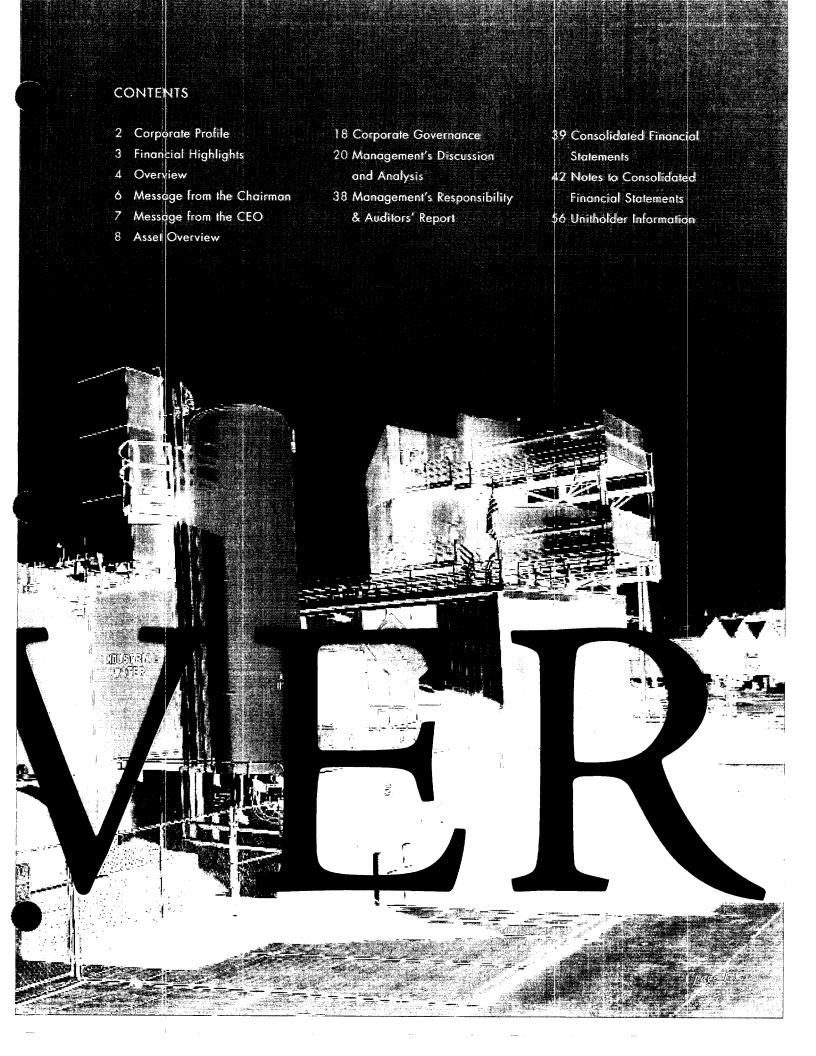


COUNTRYSIDE

2005 ANNUAL REPORT

COUNTRYSIDÉ POWER INCOME FUND • 2005 ANNUAL REPORT







the POWER of Growth

COUNTRYSIDE POWER INCOME FUND DELIVERED SIGNIFICANT ACHIEVEMENTS IN 2005:

- Raised unitholder distributions
- Executed growth and diversification strategy by acquiring natural gas-fired cogeneration projects in California
- Completed public offering to reduce debt, improve balance sheet strength and increase market capitalization
- Improved governance practices
- · Delivered increase in distributable cash flow per unit



LONG-TERM REVENUE AGREEMENTS

• Ensure revenue stability and diminish fuel price risk

DIVERSIFIED PORTFOLIO OF ASSETS AND FUEL TYPE

· Increases cash flow reliability and mitigates operating risk

EXPERIENCED AND COMMITTED OPERATOR

 Long track record of successfully managing all aspects of energy generation projects

CONSERVATIVE CAPITAL STRUCTURE

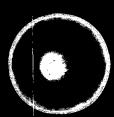
• Supports growth objectives and cash distribution stability



CORPORATE profile



Countryside Power Income Fund was created to enable investors to benefit from the rapidly growing market for independent power generation and utility-related infrastructure in North America.



Countryside's solid cornerstones provide a strong foundation for cash flow sustainability with an opportunity for growth in distributions through internal expansion and new investments. The Fund generates reliable and predictable cash flow from its asset base through underlying long-term revenue agreements. These agreements are with investment-grade customers and include provisions that mitigate fuel price risk.

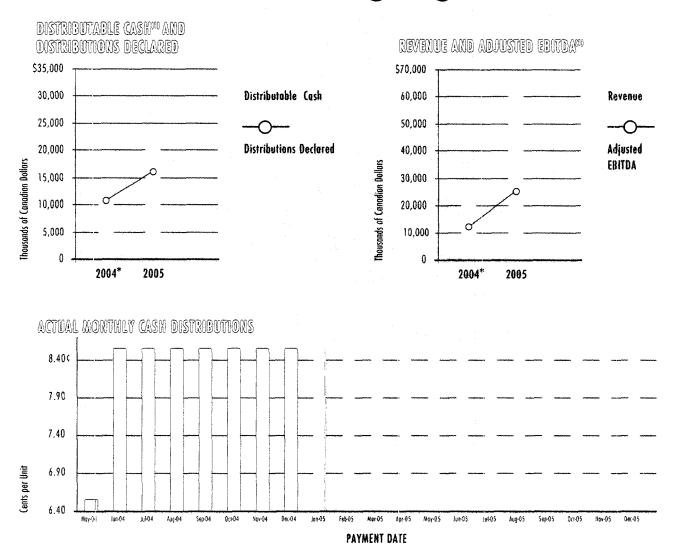


Countryside has a diversified portfolio of power assets across North America, including investments in two cogeneration projects, two district energy systems, and 22 renewable power projects. The Fund seeks to produce power and energy by using natural resources more efficiently and with less environmental impact.

The Fund's Manager is experienced in power plant and utility development, operations and financing. A board of independent trustees has primary responsibility for oversight of the Fund. The Fund's corporate governance practices are compliant with each of the Canadian Securities Administrators' Guidelines for Corporate Governance.

Countryside Power Income Fund is headquartered in London, Ontario. Its units trade on the Toronto Stock Exchange under the symbol COU,UN.

FINANCIAL highlights



Countryside makes monthly cash distributions payable on the last business day of the following month.

*267-day period ended December 31, 2004

(1) Adjusted EBITDA (earnings before interest, income taxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization) and distributable cash are non-GAAP measures. Please refer to the MD&A section on "Non-GAAP Measures".

(page 3)



the POWER

of Diverse Assets

COGENERATION **FACILITIES**

In June 2005, Countryside Power Income Fund acquired two natural gas-fired cogeneration facilities totalling 94 megawatts that are located in major metropolitan areas of California. Cogeneration is a technology that uses one fuel to produce both electric energy and useful thermal energy, which results in higher operating efficiency and lower production costs.

Fuel:

Natural gas

Contracts:

Weighted average power purchase agreements of 12 years

DISTRICT ENERGY SYSTEMS

The Fund owns two district energy systems in Canada with a combined thermal and electric generation capacity of approximately 122 megawatts. The projects are located in Charlottetown, Prince Edward Island and London, Ontario. District energy systems are a fuel-efficient and cost-effective way to provide steam and hot water to heat buildings and chilled water to cool them through an underground network of pipes in urban areas.

Fuel:

Natural Gas, Biomass, Municipal Waste, Fuel Oil Contracts: Top 10 contracts (approximately 63 of revenues) have a

weighted average remaining term of 16 years

RENEWABLE POWER

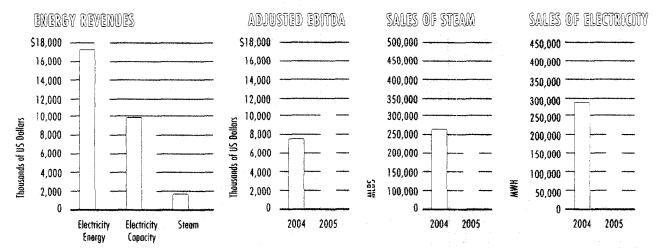
Countryside has a financial investment in 22 renewable power projects in the United States. The investment is in the form of a secured Ioan to U.S. Energy Biogas Corp. (USEB), the owner of the projects, and the Fund receives monthly payments on principal and interest. The investment is backed by a priority claim on USEB cash flows and a growing restricted cash reserve. Countryside also has a royalty interest in USEB.

Fuel:

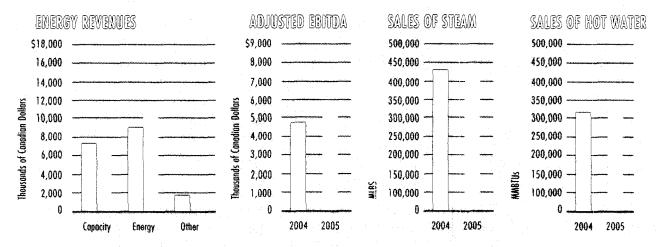
Biogas

Contracts: Countryside has more than 13 years remaining on the loan to USEB

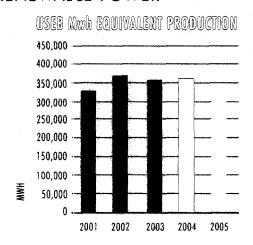
☆ COGENERATION FACILITIES



△ DISTRICT ENERGY SYSTEMS



O RENEWABLE POWER





MESSAGE from the CHAIRMAN

On behalf of the Fund's Board of Trustees, I am delighted to report that over the past fiscal year Countryside has made significant progress in advancing the two principal elements of its growth strategy: delivering stable and growing cash distributions to unitholders, and making selective investments in high-potential power and utility infrastructure projects.

Countryside has proven its ability to generate very steady cash flow through solid investments. We are also focused on growth. While we are striving to achieve further internal growth by expanding our existing customer base, improving operating efficiencies and increasing production, we are also committed to acquiring additional power and utility infrastructure assets in North America that meet our investment criteria: strong asset quality, cost competitiveness, stable cash flows, high quality customers and financial soundness.

In pursuing this strategy, the Board of Trustees must ensure that the Fund has a best-in-class management structure in place that strongly aligns the interests of unitholders with those of the Manager. At the same time, the organization must be capable of operating in a manner that minimizes development risk and increases opportunities for growth. During 2005, the Fund's board worked diligently to establish a management

arrangement that ensures operations of the Fund are prudently managed, while also creating incentives for the Manager to seek suitable growth opportunities that will increase distributable cash. We are confident this arrangement ensures Countryside has the right people in the right capacity to achieve our objectives and deliver on the performance expectations of unitholders.

Countryside Power Income Fund is committed to upholding the principles of good governance, including disclosure, transparency and integrity in serving unitholders. The Board is committed to proactively reviewing and updating our practices to stay ahead of regulatory demands and investor expectations.

The Fund has achieved a great deal in a short time. I look forward to further success in the years ahead.

Sincerely,

V. James Sardo Chairman of the Board



MESSAGE from the CEO

Fellow Unitholders,

Countryside Power Income Fund had a milestone year in 2005, marked by excellent financial results and strong growth. The Fund has successfully managed its investments in independent power and utility-related infrastructure projects in Canada and the U.S., and delivered higher cash distributions to unitholders. We significantly expanded our portfolic with the acquisition of two cogeneration facilities in California in June 2005. We enter our third fiscal year in a better position to take advantage of opportunities in the North American power market.

The acquisition of the Cogeneration Facilities meets our objectives because it:

- Diversifies our portfolio by geography, technology and asset type;
- Delivers immediate accretion to cash flow and increases cash available for distribution; and
- Creates new opportunities for organic growth in a market with sound fundamentals.

Strong Financial Results

The Fund delivered strong financial performance for the year. Countryside's consolidated revenue increased substantially from the prior year period due primarily to the successful acquisition of the Cogeneration Facilities. Revenue for the fiscal year 2005 was \$67.2 million, compared to \$21.1 million for the 267 days as a public fund in 2004. The Fund delivered significantly higher Adjusted EBITDA(1) for 2005 of \$24.5 million, compared to \$11.3 million for the 267 days in 2004. The Cogeneration

Facilities contributed six months of strong operating results in the second half of 2005, with Adjusted EBIT'DA up 38 per cent from the second half of the prior year. At the District Energy Systems, Adjusted EBIT'DA grew 27 per cent year over year.

Distributable cash⁽¹⁾ for the year was \$20.0 million and distributions declared were \$16.1 million, a payout ratio of 80.7 per cent. The payout ratio reflects the strong performance and peak operating season at the Cogeneration Facilities.

In keeping with our conservative approach, we increased cash distributions by one cent annually in September. We recently completed the refinancing of debt related to the acquisition of the Cogeneration Facilities through an offering of trust units and U.S. -dollar denominated exchangeable debentures. This resulted in lower leverage and increased market capitalization. The Fund also implemented a foreign exchange hedging program on the cash flows from the Cogeneration Facilities, ensuring there is a foreign currency hedge on substantially all U.S. dollar amounts that are required to meet the Fund's Canadiandollar denominated obligations and anticipated unitholder distributions.

Growth Strategy and Outlook

Countryside is committed to balanced and secure growth. In 2006, we will continue to focus on improvements in our operations and work to complete acquisitions of power generation assets that will further increase our scale and add to distributable cash.

The market for power generation assets is currently very active, driven in part by higher energy commodity prices. Recently enacted laws in the U.S. should spur continued consolidation in the power and utilities sector, providing as Countryside with new opportunities for measured and prudent growth. The Fund is well positioned to pursue these opportunities as they arise.

Acknowledgements

I would like to express my thanks and appreciation to our Board of Trustees for their guidance, support and insights as we completed a very busy and successful year. I am also grateful to our management team and employees for the skills and enthusiasm they bring to the challenge of achieving leadership in this industry.

Most of all, I would like to recognize the tremendous support we have received from our unitholders over the past year. We expect that our initiatives in 2006 will validate the trust you have placed in us.

Sincerely,

Göran Mörnhed President and Chief Executive Officer Countryside Ventures LLC

(1) Adjusted EBITDA (earnings before interest, income raxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization) and distributable cash are non-GAAP measures. Please refer to the MD&A section on "Non-GAAP Measures".

COUNTRYSIDE POWER INCOME FUND • 2005 ANNUAL REPORT



ASSET overview







COUNTRYSIDE HAS FOUR PILLARS THAT FORM THE FOUNDATION OF OUR STRENGTH. THESE KEY ELEMENTS ENSURE THE FUND IS RESILIENT TO EXTERNAL FACTORS AND CAN PROSPER THROUGH VARYING INDUSTRY CONDITIONS AND ECONOMIC CYCLES.

ACCUPATION OF THE PARTY OF THE

LONG-TERM AGREEMENTS ENSURE REVENUE STABILITY AND MITIGATE FUEL PRICE RISK

The Cogeneration Facilities.

District Energy Systems and
Renewable Power Projects have
long-term revenue and fuel
supply agreements with
creditworthy customers or
suppliers. The Fund is well
protected from changes in energy
prices. The Cogeneration Facilities
have fuel supply arrangements
under contract with suppliers
that are either at fixed prices or

are highly correlated with its power sales contracts via regulatory approved pricing arrangements. The District Energy Systems pass through the majority of fuel price changes to customers. The Renewable Power Projects acquire their fuel under long-term supply agreements at low fixed cost, so the business is not generally affected by market price changes of natural gas or oil.

DIVERSIFIED PORTFOLIO OF ASSETS INCREASES OPERATING STABILITY

Our investments are diversified by geography, fuel source and energy asset type. In addition, customers for both the District Energy Systems and the Renewable Power Projects are broadly based, reducing reliance on any one customer. The Cogeneration Facilities bring two new investment-grade electricity customers and two new thermal energy sustomers.



EXPERIENCED AND COMMITTED OPERATOR

Our operating staff and the operating staff of USEB's renewable power portfolio have extensive experience in managing both the commercial and operational aspects of the power and energy generation business. Several key individuals have operated or managed our underlying assets since the commencement of commercial operation or have managed similar assets in their professional careets.

CONSERVATIVE CAPITAL STRUCTURE REDUCES INTEREST RATE AND DEBT REPAYMENT RISK

The Fund is well protected from the effects of short-term interest rate changes, foreign exchange risk and refinancing risk. We have predictable debt service, which is subject to a three-year interest rate hedge on our bank debt and a fixed coupon on U.S. -dollar denominated debentures.

COGENERATION facilities

INVESTMENT IN COGENERATION FACILITIES MEETS OUR CRITERIA:

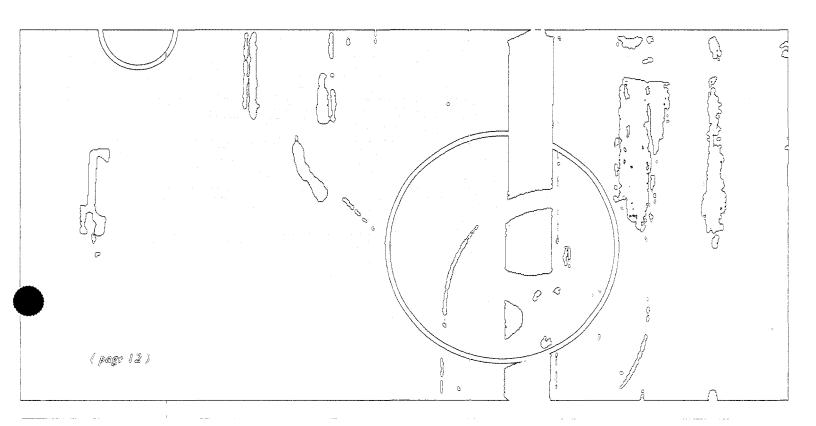
ASSET QUALITY – Our Cogeneration Facilities use proven gas-turbine technology and have long operating histories, with the Ripon facility in operation since 1988 and the San Gabriel facility since 1986. They are attractively located near urban areas with high power consumption.

COST COMPETITIVENESS - Cogeneration plants use waste energy to generate steam, which reduces the net cost to produce electricity. As a result, they are an efficient and cost competitive way to generate power.

STABLE CASH FLOWS - The Ripon facility has a power purchase agreement extending to 2018, and the San Gabriel facility has a power purchase agreement extending to 2016.

HIGH QUALITY CUSTOMERS – Both primary customers are investment grade electric utilities. The Ripon facility's primary customer is the Pacific Gas & Electric Company (the principal utility operating subsidiary of PG&E Corp., the largest electric utility in California), and the facility also sells steam to Fox River Paper Company. The San Gabriel facility sells electricity to Southern California Edison Company (the principal utility operating subsidiary of Edison International, the second-largest electric utility in California), and also sells steam to newsprint producer Blue Heron.

FINANCIALLY SOUND - Our Cogeneration Facilities have had profitable operations for almost 20 years and have ample working capital to meet their commercial obligations.



OVERVIEW

Countryside owns two Cogeneration Facilities near large urban areas in California with a combined power generation capacity of 94 megawatts. The Ripon facility is near San Francisco in Ripon and the San Gabriel facility is near Los Angeles in Pomona. These facilities sell approximately 600,000 megawatt hours of electric power annually under long-term contracts to investment grade utilities. In addition, they sell approximately 500,000 mlbs of steam annually to nearby industrial hosts, also under long-term contracts.

Conventional power plants are 30 to 50 per cent energy-

efficient, which means that between half and two-thirds of the heat they generate is lost as waste. According to the U.S. Environmental Protection Agency, cogeneration plants are up to 70 to 80 per cent efficient - a significant improvement. According to the Western Electricity Coordinating Council, estimated peak demand for electricity in California is expected to grow at an average of two per cent per year until 2013. At the same time, many of the electric generating facilities supplying peak Californian demand are approaching the end of their useful lives or are in need of retrofits to

comply with environmental standards. The combination of ageing supplies and increasing demand should provide long-term opportunities for the Ripon and San Gabriel facilities beyond their power purchase agreements.

Revenue from the Cogeneration Facilities for the six months ended December 31, 2005 was US \$28.9 million, an increase of 2.2 per cent compared to the same period last year under a prior owner. In the six-month period ended December 31, 2005, Adjusted EBITDA⁽¹⁾ increased 38 per cent to US \$10.3 million, mainly as a result of an operational focus on maximizing cash flow margins.

(1) Adjusted EBITDA (earnings before interest, income raxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization) is a non-GAAP measure. Please refer to the MD&A section on "Non-GAAP Measures".



A DISTRICT ENERGY systems

INVESTMENT IN DISTRICT ENERGY SYSTEMS MEETS OUR CRITERIA:

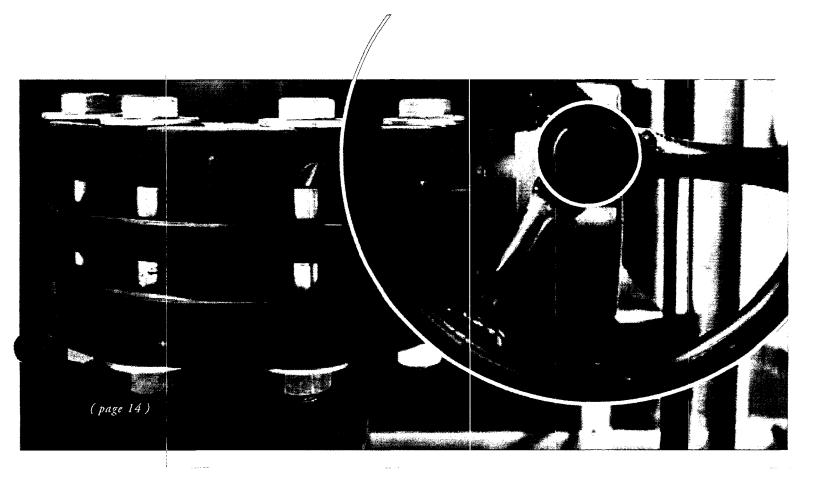
ASSET QUALITY – Our systems use proven technology and have a long history of reliable operations; major capital improvements have been recently undertaken to expand or improve both the London and PEI systems.

COST COMPETITIVENESS – The district energy systems use the most cost-effective combination of fuel and technology in their respective locations and are competitive with other local energy suppliers and self-generation. The PEI system uses municipal waste and wood waste for fuel, supplemented by fuel oil at times of peak demand, and the London system uses natural gas, with fuel oil as a back up.

STABLE CASH FLOWS – Our systems have long-term contracts with all major customers, with the top 10 customers having a weighted average remaining term of 16 years. In addition, our utility systems have a long history of a stable and growing customer base.

HIGH QUALITY CUSTOMERS - More than 76 per cent of sales are to investment grade, government or government-funded customers.

FINANCIALLY SOUND - The district energy systems have essentially no debt and ample working capital.



OVERVIEW

Countryside owns two
District Energy Systems
in Canada; one in London,
Ontario and one in
Charlottetown, Prince
Edward Island. Both
systems have operating
histories of more than
20 years and are managed
by experienced teams.
Together, they have a
thermal and electric
generation capacity of
approximately 122
megawatts.

District energy systems are common in large and mid-sized cities. Through an underground network of distribution pipes, district energy systems provide steam and hot water to heat buildings and chilled water to cool them. The pipes are connected to a central production plant, where energy is produced with higher efficiency than is traditionally achieved in individual buildings.

Customers benefit from convenient and costeffective supply of energy with higher reliability, greater fuel flexibility and efficiency and much lower environmental impact.
From a business perspective, they offer high customer retention and opportunities for continual improvements and reductions in operating costs.

Efficiency improvements completed in 2004 and early 2005 delivered additional cash flow of approximately \$350,000 in fiscal 2005.

Revenue at the Fund's District Energy Systems was \$19.8 million for the year, an increase of 11 per cent compared to a full year of operations in 2004. Adjusted EBITDA⁽¹⁾ increased by 27 per cent in 2005 over the prior year to \$5.9 million, primarily due to higher energy prices as well as efficiency and operational improvements.

(1) Adjusted EBITDA (earnings before interest, income taxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization) is a non-GAAP measure. Please refer to the MD&A section on "Non-GAAP Measures".

ORENEWABLE power

INVESTMENT IN RENEWABLE POWER MEETS OUR CRITERIA:

ASSET QUALITY – The projects use proven technology with long equipment life and predictable maintenance requirements. Biogas production is stable and is expected to increase over time because 13 of the projects are located at landfill sites that will continue to accept waste until 2037.

COST COMPETITIVENESS - The low cost of fuel and competitive operations, combined with the premium pricing for renewable power, provides for long-term cost competitiveness with other types of power generation.

STABLE CASH FLOWS – The Fund's investment in the form of a secured loan gives it a priority claim on underlying cash flows. The loan is denominated in Canadian dollars, which provides protection from U.S.-dollar exchange risk.

HIGH QUALITY CUSTOMERS - Long-term sales are mainly to large investment grade U.S. utilities, including Exelon and Dominion Resources.

FINANCIALLY SOUND - The project portfolio has working capital and significant cash reserves of more than US \$31.9 million.



OVERVIEW

Countryside Power Income Fund has an indirect investment in 22 renewable power and energy projects located in the United States. In total, these projects currently have about 51 megawatts of electric generation capacity and sell approximately 710,000 MMBtus of boiler fuel annually.

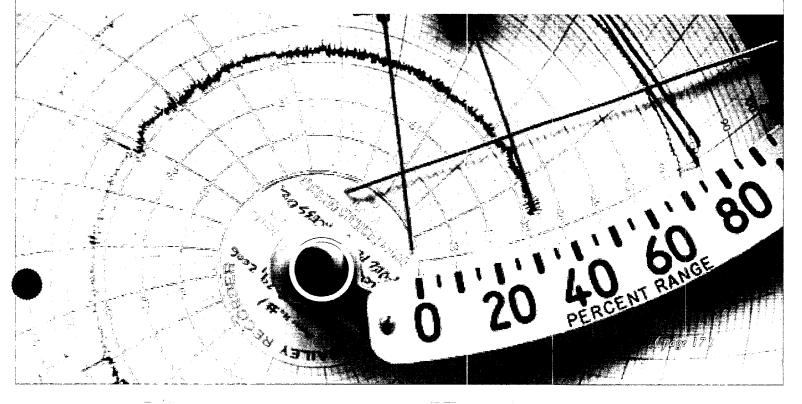
The Fund's investment consists of a secured loan to U.S. Energy Biogas Corp. (USEB). USEB owns 100 per cent of the Renewable Power Projects located outside of Illinois and 50 per cent of those located in Illinois. In addition, Countryside has the opportunity to participate

in cash flow growth through a convertible royalty interest in USEB.

The Renewable Power Projects capture landfill gas -also called biogas - in a collection system of wells and pipes. Biogas is similar to natural gas, consisting of roughly equal parts methane and carbon dioxide. It is produced by the decomposition of organic waste in landfill sites. This gas is used to fuel the reciprocating engines that drive power generators. In some circumstances, the gas may be sold directly to customers for use in firing industrial boilers and similar equipment.

The advantages of renewable power include abundance and low cost, reduced greenhouse gas emissions, long-term government support, premium pricing, low operating costs and use of a proven technology.

Interest income on loans to USEB was, as scheduled, \$11.5 million in the 12-month period ended December 31, 2005 based on a fixed interest rate of 11.0 per cent per annum. In addition to the interest income on the loans, the Fund received a total of \$1.8 million in scheduled principal repayments on the loan receivable from USEB during the year. This receipt of principal contributed to distributable cash but was not reflected in revenue.



CORPORATE governance

BOARD OF TRUSTEES

To serve the interests of all unitholders, Countryside Power Income Fund has a board of three Trustees, all of whom are independent of management. The Fund is in compliance with the Canadian Securities Administrators' guidelines on corporate governance.

The Fund has two committees: the Joint Compensation, Nominating and Governance Committee, and the Joint Audit Committee. Both committees are comprised of independent Trustees. Responsibility for all major business decisions, such as the Fund's strategy, acquisitions and divestiturds, rests solely with the independent Trustees. The chairman of the Joint Compensation, Nominating and Governance Committee is Dr. Oskar Sigvaldason, and the chairman of the Joint Audit Committee is James Anderson.

The Trustees also serve on the boards of the underlying subsidiaries of the Fund and represent a majority on the boards of all its Canadian subsidiaries.

THE FUND'S TRUSTEES ARE:

V. James Sardo - Chairman Mr. Sardo was interim Chief Executive Officer of Royal Group Technologies Limited from November 2004 to May 2005, President of the Canadian Operations of Moore Corporation Limited-a business forms and communications company from 1999 to 2001 and President and Chief Executive Officer of international automotive repair company SMK Speedy International Inc. from 1997 to 1999. Prior to 1997, M Sardo was Chief Executive Officer of Amre Inc., a Dallas-based marketer of home improvement products from 1994 to 1995 and Chief Executive Officer of SNE Inc., a manufacturer and marketer of windows and doors, from 1991 to 1994. Mr. Sardo sits on the boards of a number of public companies and income trusts and is a member of the institute of Corporate Directors.

James R. Anderson Trustee Mr. Anderson is Executive Vice President and Chief Financial Officer at Denison Mines. Previously Mr. Anderson was Managing Director of Excel Energy Group Inc. (2003-2004). Prior to that he served as Senior Vice President and Chief Financial Officer of Rogers Cable (2000-2002). He was also previously Senior Vice President of Ontario Electricity Development and Senior Vice President of Strategic Development at Westqoast Energy Inc. Mr. Anderson is a Chartered Accountant.

Dr. Oskar Sigvaldason - Trustee Dr. Sigvaldason was Chairman of the Energy Council of Canada (ECC) to the end of 2005 and continues as Past Chairman and Member of its Executive Committee. The ECC is the Canadian National Association of the World Energy Council. He is also Director and Chair; Policy Committee, of the Toronto Board of Trade. Previously, he worked with the Acres Group of companies for 39 years, where he was President and CEO from 1994 to 2003. Acres is a large global consulting engineering operation, primarily in the energy sector. He has also served as a Director of the Canadian Electricity Association. Currently, he is also a Corporate Director for other corporations. Dr. Sigvaldason holds a Ph.D., in Civil Engineering from the University of London in England.

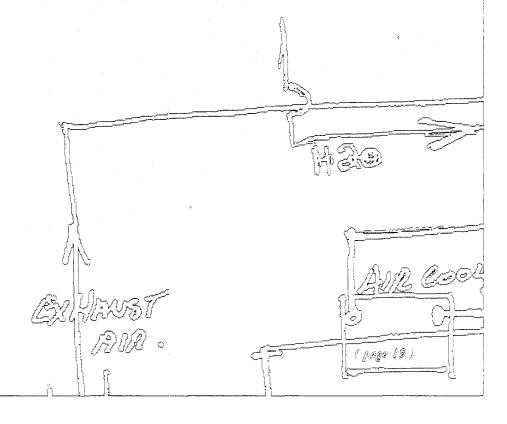
MANAGEMENT ARRANGEMENTS

In September 2005, following the acquisition of the Cogeneration Facilities, the Board of Trustees approved a new management arrangement designed to strengthen the alignment of unitholder and management interests while reducing development risk and increasing the opportunities for growth. In developing the management arrangements, the Fund's Board of Ttrustees was advised by both an independent financial advisory firm and a corporate compensation consultant.

Under the modified arrangements, Countryside Ventures LLC, a company independent of the Fund, provides management and administrative services to the Fund and develops new growth opportunities under long-term agreements. The Fund has a right of first offer for all investment opportunities developed by Countryside Ventures.

New administration and management agreements have been implemented between Countryside Ventures LLC and the Fund through its key subsidiaries, Countryside US Holding Corp. and Countryside Canada Power Inc., to provide the same services to the Fund as under the previous management arrangements, including strategic planning, investor relations, operational/financial reporting and certification, legal and regulatory compliance, and financing matters.

In addition, these new arrangements cover the development and monitoring of annual budgets and all investments, risk assessment, human resources, planning and coordination of unitholder meetings, and general administration of the Fund.



FOR THE YEAR ENDED DECEMBER 31, 2005
[ALL AMOUNTS IN THOUSANDS OF DOLLARS EXCEPT PER TRUST UNIT AMOUNTS, UNLESS OTHERWISE STATED]
MARCH 9, 2006



MANAGEMENT'S discussion and analysis

PRESENTATION OF FINANCIAL INFORMATION

Management's Discussion and Analysis ("MD&A") of the consolidated financial condition and the results of operations of Countryside Power Income Fund (the "Fund") should be read in conjunction with the audited consolidated financial statements and notes thereto prepared as of and for the year ended December 31, 2005 and for the period from February 16, 2004 to December 31, 2004.

This MD&A provides information for the period from January 1 to December 31, 2005 and for the three months ended December 31, 2005, up to and including March 9, 2006.

Forward-Looking Information

This MD&A may contain forwardlooking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time-to-time in the Fund's Annual Information Form dated March 31. 2005 as well as in the Fund's short-form prospectus dated November 8, 2005 filed with the Canadian Securities regulatory authorities. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking

statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

Non-GAAP Measures

Earnings before interest, income taxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization ("Adjusted EBITDA") is not a measure under Canadian GAAP and there is no standardized measure of Adjusted EBITDA and therefore, it may not be comparable to similar measures presented by other funds or companies. Adjusted EBITDA can be calculated from the Fund's GAAP statements as operating income, plus depreciation and amortization expense. The Manager of the Fund (as defined below) believes that Adjusted EBITDA is a widely accepted

financial indicator used by investors to assess the operational performance of a company or fund, and its ability to generate cash through operations.

Distributable cash is not a measure under Canadian GAAP and there is no standardized measure of distributable cash and therefore, it may not be comparable to similar measures presented by other funds or companies. The Fund distributes substantially all of its cash on an on-going basis. Distributable cash is a widely accepted financial indicator used by investors to assess the performance of an income trust and its ability to generate cash for distributions through ongoing operations.

OVERVIEW OF FUND AND RECENT DEVELOPMENTS

2005 Highlights

- Unitholder distributions were raised from \$1.025 to \$1.035 on an annual basis
- Cash available for distribution increased to \$20,012
- The Fund executed on its growth strategy and acquired two power generation facilities in U.S.:
 - The acquisition was immediately accretive to distributable cash per unit
 - The acquisition related debt was refinanced, resulting in lower leverage and increased market capitalization while maintaining cash accretion per unit
- The Fund's management arrangements were modified to strengthen governance practices and to facilitate opportunities for further accretive investments in power generation and utility infrastructure

Overview

The Fund, through its operating subsidiaries, owns two district energy systems and two gas-fired cogeneration facilities. The district energy systems are located in Canada, with one in Charlottetown, Prince Edward Island (the "PEI System") and one in London, Ontario (the "London System"), and together have approximately 122MW of thermal and electric generation capacity (collectively, the "District Energy Systems"). The cogeneration facilities consist of the Ripon cogeneration plant ("Ripon Facility") located near San Francisco, California and the San Gabriel cogeneration plant ("San Gabriel Facility") located near Los Angeles. California (collectively, the "Cogen Facilities") and have approximately 94 MW of electric generation capacity, sold approximately 500,000 Mlbs (thousand pounds) of steam in 2005 and its principal assets. In addition, the Fund holds indirect investments in 22 renewable power and energy projects (the "Renewable Projects")

located in the United States, which currently have approximately 51MW of electric generation capacity and sold approximately 710,000 MMBtus of boiler fuel in 2005. The Fund's investment in the Renewable Projects consists of loans to, and a convertible royalty interest in, U.S. Energy Biogas Corp. ("USEB"). USEB is a company unrelated to the Fund and has its own management and operations staff.

The Fund's objectives are to maintain the stability and sustainability of cash distributions to unitholders of the Fund ("Unitholders") and increase, when prudent, cash distributions per unit. In order to achieve these objectives, the Fund intends to focus on enhancing the current operational practices of its existing businesses, pursuing internal growth and expansion opportunities, and making additional investments in power generation and utility infrastructure projects, including, among others, cogeneration projects, renewable energy projects and district energy systems.

Recent Developments

Acquisition of Ripon Power LLC

On June 29, 2005, the Fund, through an indirect subsidiary, completed the acquisition of a 100% controlling interest in Ripor: Power LLC ("Ripon Power") the holding company of Ripon Cogeneration LLC, a California-based power generation company, which owns the Cogen Facilities. In the transaction, the Fund, acquired Ripon Power for consideration of US \$35,800 in cash plus the assumption of non-recourse project debt of US \$59,500 for a total transaction value of US \$95,300, or approximately CDN \$117,000 based on exchange rates in effect on the date of closing. The Fund financed the acquisition through an expansion of its existing credit facility with a syndicate of banks led by the Toronto-Dominion Bank (the "Amended Credit Facility"). The Amended Credit Facility commitment has a maximum limit of \$80,000.

Trust Unit and Exchangeable Debenture Offering (the "Offering")

On November 14, 2005, the Fund and Countryside Canada closed an offering of 4,720,000 trust units at \$9.35 per unit for gross proceeds of \$44,132 and US \$55,000 aggregate principal amount of 6.25% exchangeable unsecured subordinated debentures ("Debentures"), due October 31, 2012. The Debentures were issued by Countryside Canada Power Inc. ("Countryside Canada"). Upon closing of the Offering, net proceeds were used to repay indebtedness under the Amended Credit Facility associated with the acquisition of Ripon Power, to acquire project-related debt of the Cogen Facilities from a syndicate of U.S. based lenders, with the excess remaining proceeds used for working capital purposes.

Increase in Unitholder Distributions and Management Agreement

On September 23, 2005, the Fund announced an increase in its annual distribution of \$0.01 per unit. The first distribution under the new rate was paid on October 31, 2005 to unitholders of record on September 30, 2005.

Also on September 23, 2005, the indirect and direct subsidiaries of the Fund, Countryside US Holding Corp. ("Countryside US Holding") and Countryside Canada, respectively, entered into a management agreement with Countryside Ventures LLC (the "Manager") (the "Management Agreement"). Under the terms of the Management Agreement, which became effective November 1, 2005, the Manager will provide management and administrative services to the Fund, as well as new growth opportunities, under long-term agreements. The Manager will employ the Fund's current executive management team on a full time basis as well as its administrative and development staff. The Fund, through Countryside US Holding and Countryside Canada, has a right of first offer on all investment opportunities developed by the Manager that meet the Fund's investment criteria. In consideration for providing the management and administrative services under the Management Agreement, the Manager shall be entitled to reimbursement from the Fund of all costs and expenses reasonably incurred by the Manager and its affiliates in carrying out the services described above.

The Management Agreement also provides for compensation through a long-term incentive plan for each new asset, company or investment, acquired or made, by the Fund or any of its affiliates, and originated, structured or developed through the efforts of the Manager or its affiliates (the "LTIP"). Under the LTIP, the Manager will be entitled to a distribution from the new asset's operating or investment cash flow equal to 25% of the cash distributions made in excess of the preferred distribution made to the Fund, as defined in the Management Agreement. In the case of the Cogen Facilities, the Manager holds a subordinated membership interest in Ripon Power and will share with the Fund, to the extent available, the excess operating cash flow of the Cogen Facilities on a 25% and 75% basis, respectively.

OPERATING RESULTS

CONSOLIDATED RESULTS OF THE FUND

Countryside's total revenue for the three months ended December 31, 2005 was \$23.8 million, an increase of \$16.0 million compared with the same period last year, primarily as a result of the acquisition of the Cogen Facilities. Excluding the effect of the acquisition, revenue would have been \$8.7 million, up 10.7% from \$7.9 million in the same period in 2004, primarily due to higher revenues at the District Energy Systems. In the year ended December 31, 2005, revenue was \$67.2 million. Since the Fund commenced operations on April 8, 2004, there is no comparable 12 month period in 2004 at the Fund level.

The Fund's Adjusted EBITDA in the three-months ended December 31, 2005 was \$6.5 million, an increase of \$2.6 million from the prior year period, again due primarily to the addition of the Cogen Facilities. Excluding the quarterly results of Ripon and other Ripon-related expenses, Adjusted EBITDA would have been \$4.2 million in the fourth quarter, an increase of 9.7% compared to \$3.8 million in the prior year period. For the year ended 2005, Adjusted EBITDA was \$24.5 million.

Operating income for the three-months ended December 31, 2005 was \$3.4 million, an increase of \$0.3 million from the prior year comparative period. The Cogen Facilities did not impact the results as significantly on an operating income basis as they did on the revenue and Adjusted EBITDA measures, due to the significant increase in depreciation and amortization resulting from the acquisition of the Cogen Facilities. Operating income for the year ended December 31, 2005 was \$16.4 million.

Net income in the three-month period ended December 31, 2005, was \$4.0 million or \$0.24 per unit, compared with \$2.2 million or \$0.14 per unit in the comparable period of 2004. The increase in net income from the prior quarter comparative period was driven by a number of factors in addition to those described above related to the increases

in Adjusted EBITDA and operating income as a result of the acquisition of Ripon Power, as follows: (i) approximately \$1.7 million related to a decrease in the tax provision, partially related to deferred taxes on losses not previously recognized; (ii) an increase in net realized and unrealized gains on interest rate swaps of approximately \$1 million primarily as a result of the settlement of an interest rate swap associated with the acquired Ripon project debt and (iii) an unrealized foreign exchange gain of approximately \$0.8 million related to the carrying value of the US dollar denominated Debentures. Offsetting these increases was an increase in interest expense of \$1.8 million relating to increased debt resulting from the amended credit facility and interest on the Debentures issued during the fourth quarter. Net income was \$13.2 million or \$0.85 per trust unit for the year ended December 31, 2005 compared with \$7.6 million or \$0.51 per trust unit for the prior comparative period.

RESULTS OF DISTRICT ENERGY SYSTEMS

As the Fund was created on February 16, 2004, and acquired the operations of the District Energy Systems on April 8, 2004, the comparative period ended December 31, 2004 includes 267 days of operations and therefore for comparative purposes, the 2004 consolidated financial statements of the Fund exclude the period from January 1, 2004 to April 8, 2004. In order to enhance its usefulness, the analyses included in this MD&A of the District Energy Systems include the summary of the operating results of the District Energy Systems from January 1, 2004 to December 31, 2004. This information is provided for reference purposes only and is not intended as a comprehensive comparison of financial results of the District Energy Systems.

The District Energy Systems' revenue is mainly derived from long-term energy sales contracts with long-standing and creditworthy customers. The energy sales contracts are generally structured with energy and capacity payments, with the energy component typically providing for

the pass through of changes in fuel prices to the customers. The energy rates paid by customers in London are generally reflective of the price of natural gas and are adjusted upward or downward to compensate for changes in the price of natural gas. In regard to the PEI System, the energy rates paid by larger customers are generally reflective of the cost and mix of fuels and are adjusted upward or downward to compensate for changes in the price of fuel. Smaller customers of the PEI System have rates based on the local price of fuel oil. For such customer rates, changes in the local fuel price will have a greater impact on the revenues of the PEI System than the impact that such changes will have on the cost of operation of the PEI System. As a result of the energy rate pricing structures, the District Energy Systems' revenue can increase or decrease depending on changes in fuel prices and, to a lesser extent, the fuel mix. During the last year, the global market price increases for natural gas and oil have affected our District Energy Systems in terms of both increased fuel costs and corresponding increased energy revenues.

District Energy Financial Results

	Three-month period ended December 31, 2005	Three-month period ended December 31, 2004	Twelve-month period ended December 31, 2005	Twelve-month period ended December 31, 2004
Energy Volumes				
Sales of Steam (MIbs) (Combined PEI & London Systems)	114,190	116,951	422,826	425,752
Sales of Hot Water (MMBtus) (PEI System only)	88,053	88,28 <i>7</i>	313,314	312,350
Sales of Chilled Water (MTon/hr) (London System only)	268	257	2,913	2,423
Fuel Consumed (MMBtus) (Combined PEI & London Systems)	305,58 <i>7</i>	328,596	1,138,032	1,1 <i>77</i> ,428
Financial Indicators [000's]	\$	\$	\$	\$
District Energy Systems' Energy Revenues	5,188	4,426	1 <i>7</i> ,932	16,139
Capacity	1,8.74	1,820	7,371	7,080
Energy	3,314	2,606	10,561	9,059
Other Revenues	447	388	1,894	1,691
Fuel and Consumables Expense	2,688	2,271	8,548	<i>7,</i> 881
Operating, Labour and Maintenance Expense	1,107	965	4,346	4,294
General and Administration Expense	280	272	1,046	1,030
Adjusted EBITCIA	1,560	1,306	5,886	4,625
Depreciation and Amortization Expense	348	340	1,469	1,248
Operating Income	1,212	966	4,417	3,377

Energy Volumes and Revenues

In the three-month period ended December 31, 2005, the District Energy Systems' steam sales volumes decreased from the prior year results by approximately 2%. These reductions were principally based on more moderate temperatures resulting in lower energy requirements from customers for heating. Hot water sales volumes were consistent with the prior year comparative period.

In the twelve-month period ended December 31, 2005, the District Energy Systems' energy volumes sold for steam and hot water were essentially flat. Steam sales volumes decreased by less than 1% while hot water sales volumes increased by less than 1%. Increased volumes during the first quarter heating season were offset by lower volumes during the remainder of the year.

Sales volumes of chilled water for the three-month period ended December 31, 2005 increased approximately 4% over the prior year and for the twelve-month period ended December 31, 2005 chilled water sales volumes increased by 20% over the same period in 2004. These increases were due to higher cooling requirements as a result of warmer than average temperatures primarily during the second and third quarters of 2005.

In the three-month period ended December 31, 2005, total revenues from District Energy Systems' energy sales increased by 17% from the prior year period. The increase in energy revenue was due primarily to energy rate increases, resulting from higher fuel prices that are passed through to customers as well as higher customer contract reference prices. In the year ended December 31, 2005, total District Energy Systems' energy revenues increased approximately 16%, also primarily resulting from increases in energy revenues, which were due to customer fuel price increases. Capacity payments increased by approximately 4%, reflecting contract price index adjustments. Capacity payments are fixed payments, which are received regardless of energy volumes delivered.

Other Revenues

Other revenues consist of waste fuel fees received at the PEI System as well as other miscellaneous revenue items.

Such revenue increased in both the three-month and twelve-month periods enced December 31, 2005 from their respective comparative prior year periods primarily due to contract price increases as well as higher waste volumes processed.

Fuel and Consumables Volume and Expense

In the three-month period ended December 31, 2005 total fuel consumed by the District Energy Systems decreased 23,000 MMBtu or 7% and decreased by 39,000 MMBtu or 3% for the year ended December 31, 2005. The decrease in both periods was essentially due to the increased efficiency recognized at the London System as a result of the capital improvement program substantially completed in the first quarter of 2005.

Fuel and consumables expense increased 18% and 8% in the three months ended December 31, 2005 and the year ended December 31, 2005, respectively. The increase in both periods was due primarily to an increase in the price of gas consumed at the London System. Increased costs were offset approximately \$350 for the twelve-month period ended December 31, 2005 by reduced consumption resulting from efficiency improvements.

Total Non-Fuel Expenses

In the three-month period ended December 31, 2005, operating, labour and maintenance expense was \$1,107, 15% higher than the prior comparative three-month period. In the year ended December 31, 2005 operating labour and maintenance and repairs were 1% higher than the prior year comparative period. The increase for both periods was related to plant equipment and distribution system maintenance for both systems.

General and administration expenses were only negligibly higher in both the quarterly period ended December 31, 2005 and for the year ended December 31, 2005, when compared to their respective prior year periods.

Adjusted EBITDA

In the three-month period ended December 31, 2005, Adjusted EBITDA increased 20% from \$1,306 to \$1,560 when compared to the prior year period, mainly a result of higher margins from district energy sales at both systems resulting from higher fuel prices

combined with improved fuel efficiencies at the London System. In the year ended December 31, 2005, Adjusted EBITDA increased 27% from \$4,625 to \$5,886 when compared with the prior year period at both district energy systems due to improved operational efficiencies and higher margins from district energy sales resulting from higher fuel prices.

Depreciation and Amortization Expense

The increase in depreciation and amortization expense in both the three-month and twelve-month periods ended December 31, 2005 was mostly due to an increase in property, plant and equipment depreciation related to the increase in capital assets including the improvements at the London System.

RESULTS OF COGEN FACILITIES

Power Purchase Agreements

The Ripon Facility is a nominal 49.5 MW (gross output) gas-fired cogeneration plant and the San Gabriel Facility is a nominal 44.5 MW (gross output) gas-fired cogeneration plant. The Cogen Facilities are qualifying facilities ("QFs") under the cogeneration regulations of the Federal Energy Regulatory Commission ("FERC") implementing the Public Utilities Policy Act of 1978 ("PURPA") and thus are currently exempt from rate regulation as an electric utility under federal and state law. Power sales comprise the bulk of the Cogen Facilities sales revenue. Electrical capacity and energy is sold pursuant to long-term power purchase agreements ("PPA") with Pacific Gas & Electric ("PG&E") and Southern California Edison ("SCE") for the Ripon and San Gabriel Facilities, expiring in 2018 and 2016, respectively. For the full operating year, energy payments under the PPA have historically contributed the majority of total power sales with capacity payments making up the balance.

In 2001, the Ripon Facility and PG&E entered into a five year interim agreement of the Ripon Facility's power purchase agreement which substituted PG&E's marginal production or short-run avoided cost ("SRAC") with a primarily fixed energy rate subject to adjustment for time of use factors ("Ripon Amendment").

As a result, the Ripon Facility receives energy payments from PG&E that correlate with the prices charged for fuel under the natural gas contract with BP Energy Company ("BP"). The San Gabriel Facility currently receives a monthly energy payment for energy delivered to SCE in an amount calculated by reference to a SRAC pricing formula specified in the five year interim agreement of its PPA which terminates no later than July 1, 2006 ("SG Amendment"). As a result of the SG Amendment, the San Gabriel Facility receives energy payments from SCE that correlate with the prices charged by BP under the natural gas supply contract, as SCE's SRAC and BP's pricing formula inputs are both derived from the same regional gas price indices.

When both the Ripon and San Gabriel Amendments expire in mid-2006, it is expected that the Ripon Facility and San Gabriel Facility, respectively, will again receive energy payments under their respective PPAs based on each of their utility customer's full SRAC energy prices, which are generally derived from their respective regional natural gas price index and utility system heat rates. There is an open proceeding in which the California Public Utilities Commission ("CPUC") has indicated it will review the formula for California SRAC pricing for possible prospective changes (See "Risks and Uncertainties - Electricity Pricing"). Although the Ripon and SG Amendments expire in mid-2006, it does not alter PG&E's or SCE's commitment to make both firm energy and capacity payments to both the Ripon Facility and the San Gabriel Facility until the PPAs expire in 2018 and 2016, respectively.

Steam Sales Agreements

Process steam from each of the Cogen Facilities is sold under long term steam sales agreements, which are coterminous with the PPAs. On a combined basis,

process steam sales has accounted for an average of approximately 6% of total energy revenues based on results for the six-month periods ended December 31, 2004 and 2005.

Fuel Supply Agreements

Full natural gas requirements are supplied to the Cogen Facilities under contracts with BP that expire on June 30, 2006. Prior to the expiry of the existing fuel contracts, the Cogen Facilities intend to enter into new contracts with one or more investment grade gas supplier(s) that would provide full natural gas requirements to meet electric power and thermal supply commitments under the PPA and steam sales agreements. Pricing is expected to be structured to substantially correlate with the SRAC energy pricing formula in effect when the Ripon and SG Amendments expire on a concurrent basis (See "Risks and Uncertainties -Risks Related to Operations").

Cogen Facilities' Financial Results

	Three-month period ended December 31, 2005	Three-month period ended December 31, 2004	Six-month period ended December 31, 2005	Six-month period ended December 31, 2004
Energy Volumes				
Sales of Electricity (MWh)	103,533	158,480	236,819	28 <i>7</i> ,833
Sales of Steam (Mlbs)	125,893	13 <i>7</i> ,880	242,246	261,423
Fuel Consumed (MMBtus)	1,083,812	1,559,424	2,437,922	2,962,334
Financial Indicators (US \$000)	US\$	US\$	US\$	US\$
Cogen Facilities' Energy Revenues	12,537	13,029	28,871	28,1 <i>7</i> 4
Electrica [†] Energy	9,882	9,919	18,137	17,064
Electrica [†] Capacity	1,746	2,217	8,986	9,443
Steam	1,009	893	1,748	1,667
Other Revenues	26	58	40	90
Fuel and Consumables Expense	6,907	9,408	14,535	16,701
Operating, Labour and Maintenance Expense	1,950	1,949	3,673	3,599
General and Administration Expense	471	262	622	500
Adjusted EBITDA (US\$000)	3,335	1,468	10,081	7,464
Depreciation and Amortization Expense	1,788	1,314	3,943	2,625
Operating Income (USS000)	1,347	154	6,138	4,839
	(DN\$	CDN\$	CDN\$	CDN\$
Adjusted EBITDA (\$000)	3,954	1,786	12,182	9,674
Operating Income (\$000)	1,571	187	7,414	6,272

The results of the Cogen Facilities will be discussed in thousands of US Dollars since the exchange to Canadian dollars skews the actual results of operations.

Energy Volumes and Revenues

In the three-month period ended December 31, 2005 electrical energy sales volumes decreased by 35% from the prior year comparative period. The decrease in electricity production was due to a planned maintenance shutdown of the Ripon Facility during November and December, 2005. The 18% decrease in the six-month period ended December 31, 2005 when compared with the prior year period was primarily for the same reason.

In the three-month period ended December 31, 2005, steam sales volumes decreased by 9% from the prior year period and decreased by 7% in the comparative six-month period ended December 31, 2005 due to decreased demand from the steam hosts.

Electrical energy revenue decreased only marginally when compared with the prior year three-month period ended December 31, 2004 despite the 35% reduction in electrical energy sales volumes. The small revenue decrease, when compared to the larger volume decrease in the same period was due to higher energy rates at the San Gabriel Facility, resulting from higher fuel prices, which were passed through to customers. Electrical capacity revenue, which is based on the Facilities' availability factor, decreased 21% from the prior year comparative period. This was due to the maintenance shutdown during the off-peak months of November and December 2005 at the Ripon Facility.

In the six-month period ended December 31, 2005, electrical energy revenues increased by 6% when compared with the prior year period for the same reason. Electrical capacity revenue decreased by 5% in the six-month period ended December 31, 2005 as described above for the three-month period results. Steam revenues increased by 5% when compared to the prior year period for the same reason that the electrical energy revenues increased.

Other revenues consist of interest income earned during the period.

Fuel and Consumables Volumes and Expense

Fuel consumed in the three-month period ended December, 31, 2005 decreased primarily due to the Ripon Facility planned maintenance shutdown during November and December of 2005, by 475,612 MMBtus or 31% when compared to the prior year period. The same occurrence caused the decrease of 18% in fuel consumed during the sixmonth period ended December 31, 2005.

During the Ripon Facility's maintenance shutdown, BP, Ripon's fuel supplier, remarketed approximately 549,000MMBtus of natural gas not delivered to the Ripon Facility at economically favourable pricing. The associated savings of \$2,530 were credited to the Ripon Facility and reduced its' fuel and consumables expense, resulting in decreased fuel costs of 27% for the three-month period December 31, 2005. Fuel costs decreased by 13% from the prior year six-month comparative period ended December 31, 2004. The fuel cost decrease was primarily due to the Ripon Facility's maintenance shutdown resulting in fuel cost savings as described above, offset by an increase in the cost of fuel at the San Gabriel Facility due to an increase in the average gas price for the six-month period ended December 31, 2005 when compared to the same six-month period in 2004.

Total Non-Fuel Expenses

Operating, labour and maintenance expense in the three-month period ended December 31, 2005 was similar to the prior year comparative period. Expenses in the six-month period ended December 31, 2005 increased by 2% when compared to the prior year period, mainly due to marginally increased labour and supervision expenses.

General and administration expense in the three-month period ended December 31, 2005 increased 80% when compared to the prior year period as a result of transactional advisory costs related to the acquisition of the Ripon Facilities by the

Fund. Expenses in the six-month period ended December 31, 2005 increased by 24% when compared to the prior year period, due to the advisory costs notes above, coupled with costs incurred in 2004, related to a possible Ripon Facility expansion which were not similarly incurred in 2005.

Adjusted EBITDA

Adjusted EBITDA increased by \$1,867, or 127% in the three-month period ended December 31, 2005 compared with the prior year period, mainly due to improved operational performance and the lower fuel costs at the Ripon Facility. In the six-month period ended December 31, 2005, Adjusted EBITDA increased \$2,617 or 35% for the same reasons.

Depreciation and Amortization Expense

Depreciation and amortization increased in both the three-month and six-month periods ended December 31, 2005 when compared to their respective prior year periods. The increases were as a result of the assessment and corresponding changes in the fair values of the property, plant and equipment and other intangibles on the date of acquisition by the Fund and the resultant change in depreciation and amortization expense.

RESULTS OF CORPORATE AND OTHER

Corporate and Other results as presented below include the Fund's loan to, and convertible royalty interest in, USEB as well as its' corporate administrative operations, including those related to the Cogen Facilities. The Fund was created on February 16, 2004 and was dormant until April 8, 2004, thus the results in the twelve-month period ended December 31, 2004 are not comparative and, as such, will not be discussed.

	Three-month period ended December 31, 2005	Three-month period ended December 31, 2004	Year ended December 31, 2005
•	\$	\$	\$
Interest Income on Loans to USEB	2,868	2,91 <i>7</i>	11,546
Other Revenues	221	147	849
Total Revenue	3,089	3,065	12,395
General and Administration Expense	2,117	524	5,953
Adjusted EBITDA	972	2,541	6,442
Depreciation and Amortization Expense	366	382	1,824
Operating Income	606	2,159	4,618

Revenue

Interest Income on Loans to USEB

Interest income on loans to USEB was, as scheduled, \$2,868 in the three-month and \$11,546 in the twelve-month period ended December 31, 2005 based on a fixed interest rate of 11.0% per annum on the loan balance remaining as at December 31, 2005 of \$103,961. The USEB loan pays principal and interest monthly. As at the end of December 31, 2005, the Fund received a total of \$476 in scheduled principal repayments on the loan receivable from USEB during the quarterly period and \$1,828 during the twelve-month period.

The terms of the USEB loan agreements require that USEB establish various restricted reserve accounts upon origination of the loan and to fund two of those reserves on an ongoing basis from available cash flow. USEB's ten Illinois-based projects receive a subsidy from the State of Illinois ("ICC Subsidy") and a portion thereof is set aside on a monthly basis into a reserve account ("ICC Reimbursement Account"). On December 31, 2005, the total investment value of the ICC Reimbursement Account was US \$26,429. The ICC Reimbursement account is invested in a balanced portfolio of liquid equity and fixed income instruments. The investments in the ICC Reimbursement Account and the ICC subsidy received under various power sales contracts have been pledged to collateralize repayment of the USEB loan to the Fund. In addition, USEB is required to fund a Debt Service Reserve Account ("USEB DSR") on a quarterly basis from available cash flow after payment of all operating and maintenance expenditures, debt service, and ICC Subsidy Deposits but before growth capital expenditures and dividends (including the convertible royalty interest). On December 31, 2005, the USEB DSR had an investment value of US \$2,104. The USEB DSR cash deposits have been invested in high quality liquid instruments and also have been pledged to the Fund to secure repayment of the loan. The USEB DSR can be drawn upon first by the Fund to meet debt service on the USEB loan to the extent USEB operating cash flow is insufficient. Including a construction reserve account at the USEB level in the amount of US \$3,366, there were liquid reserves in excess of US \$31,899 that collateralize the repayment of the USEB loan to the Fund as of December 31, 2005. In addition, the Fund's investment is collateralized by all of USEB's assets and energy sales contracts.

Other Revenues

Other revenue at the Fund level is comprised of USEB royalty interest, fee revenue from U.S. development partners as well as miscellaneous interest income on cash equivalents held at the Fund level.

Total General and Administration Expenses

In the three-month period ended December 31, 2005, general and administration expense increased by \$1,593. The subordinated distribution accrued to the Manager in the quarter

was \$715. A further \$549 of the increase related to accruals for increased compensation in connection with the Fund's expanded operations and meeting certain operational and growth related incentive targets' pursuant to the terms of the Management Agreement. Development fee revenue and expenses owing from U.S. Energy Systems, Inc. ("USEY") accrued during the period from May through September 2005 of approximately \$165 were written off during the fourth quarter of 2005, further contributing to the comparative increase. The remainder of the increase in general and administration costs related primarily to incremental costs associated with increased transfer agent, audit, tax and insurance accruals.

In the year ended December 31, 2005, the \$5,953 of general and administration expense included the subordinated distribution accrued to the Manager of \$1,993, as described above, as well as the reimbursement of transaction costs of \$437 paid to the Manager related to the Ripon Power acquisition. The other cost differences from the prior period ended December 31, 2004 occurred primarily during the fourth quarter of 2005 as outlined above. In the three-month period and the year ended December 31, 2005, transaction costs related to the Ripon transaction of \$642 and \$1,080, respectively, were expensed, but were not deducted in the calculation of distributable cash per unit, as the costs were part of the Ripon transaction and not paid from cash flow from regular operations.

Adjusted EBITDA

Adjusted EBITDA decreased by \$1,569 or 62% in the three-month period ended December 31, 2005 compared with the three-month period ended December 31, 2004 due to a slight decline in revenue coupled with an increase in expenses as described above. The Manager's share of the Subordinated Distribution which accounted for half of the increase in general administrative expenses are not an ongoing cost to manage the Fund's operating activities.

Depreciation and Amortization Expense

There was little change in depreciation and amortization expense in the comparative three-month period ended December 31, 2005.

DISTRIBUTIONS DECLARED TO UNITHOLDERS

While the first quarter of the calendar year is generally the most profitable quarter for the District Energy Systems, the second and third quarters are generally the weakest quarters due to warmer temperatures which result in lower demand for thermal energy requirements by customers. The results of the Cogen Facilities directly offset this pattern in that their most profitable quarters are generally the second and third quarters when capacity payments under the power purchase agreements are the highest. On a consolidated basis, cash flow is expected to be greatest during the second and third quarters on an ongoing basis due to the contribution from the Cogen Facilities.

	Three-month period ended December 31, 2005	Year ended December 31, 2005	267-day period ended December 31, 2004
	\$	\$	\$
Cash provided by operating activities	3,145	16,541	8,708
Add: Changes in working capital	2,205	2,393	1,409
Funds from operations before working capital changes	5,350	18,934	10,117
Add:			
Receipt of principal on USEB loans	476	1,828	1,211
Transaction costs expensed ¹	642	1,080	n
Deduct:			
Principal repayments on Cogen Facilities' project-related debt	-	95 <i>7</i>	-
Purchases of capital assets for regular operations ²	128	504	253
Royalty Interest ³	133	369	٠
Distributable cash for the period	6,207	20,012	11,075
Distributions declared for the period	4,674	16,145	11,161
Distributable cash per Trust Unit for the period	0.364	1.290	0.743
Distributions declared per Trust Unit for the period (whole dollars)	0.271	1.041	0.749

¹ Transaction costs related to the Ripon acquisition transaction were paid to the Manager and advisors out of financing proceeds and were not operational in nature

² Purchases of capital assets for regular operations are non-expansionary capital expenditures. Total capital expenditures for the year ended December 31, 2005 were \$855.

³ As the timing of the receipt of the royalty interest income earned in a period is dependent upon the timing and extent of equity distributions made by USEB to its shareholders', royalty interest income will only be included in the calculation of distributable cash when payments related to the royalty interest are received from USEB. This method of calculating distributable cash was adopted retroactively in the three-month period ended March 31, 2005. Prior to January 1, 2005, distributable cash included royalty interest income as earned.

The Fund pays monthly cash distributions to Unitholders on or about the last business day of each month to Unitholders of record on the last business day of the prior month. The ex-distribution date is two business days prior to the last business day of the prior month. From the inception of the Fund on April 8, 2004 up to the distribution declared in September 2005, all distributions declared have been \$0.0854 per month, except for the distributions payable December 31, 2004 and June 30, 2005 which were \$0.0855 to make up for rounding differences. On September 23, 2005 the Fund announced an increase in distributions to approximately \$0.0863 per month, which is equivalent to \$1.035 per trust unit per annum.

The Fund intends to meet future distribution payments from cash flow generated from its operating assets and investments, and expects to maintain cash distributions for the 2005 year at the increased level of \$1.035 as noted above, compared with annualized distributions, since inception, of \$1.025 per Trust Unit.

The composition of distributions paid by the Fund for 2004 was approximately 71% return on capital and 29% return of capital. The Manager estimates that in 2005, the composition of distributions for tax purposes will be approximately 66% return on capital and 34% return of capital.

LIQUIDITY AND CAPITAL RESOURCES

The Fund expects to be able to meet all of its obligations from cash flow from operations and investments. Additionally, the Fund has \$10,312 of cash on hand. As of December 31, 2005, the Fund's three-year \$80,000 Amended Credit Facility had on outstanding balance of \$47,500. Additionally, a US \$3,000 Letter of Credit was outstanding, and \$1,615 was drawn on the swing line of credit, leaving \$27,396 in available credit. This remaining unutilized commitment amount remains available for working capital purposes, including financing new growth and the expansion of existing facilities. On November 14, 2005, the date of the closing of the Offering, the Fund repaid \$30,500 of the Amended Credit Facility and an indirect subsidiary of the Fund acquired the Cogen Facilities' project-related debt with an outstanding balance of US \$58,718 and repaid a working capital revolver loan for US \$500. The project-related debt at the Cogen Facilities' was acquired and amended to an amount of approximately US \$52,000 (the "Countryside Holding Note").

Cash used in investing activities was \$41,830 in the twelve-month period ended December 31, 2005, due to the acquisition of Ripon Power, which

required \$42,803 in cash, coupled with scheduled repayments of \$1,828 received by the Fund on the USEB loan offset by \$855 in capital expenditures. Of the capital expenditures, \$504 was operations related capital expenditures and \$351 were growth capital expenditures, the majority of which related to the efficiency improvements at the London System.

Net cash provided by financing activities consists primarily of the net cash received related to the Offering of \$41,155 for units and \$60,258 for the Debentures as well as increased borrowings on the Amended Credit Facility of \$48,000 to finance the acquisition of Ripon Power. This cash inflow was offset by the acquisition of the Cogen Facilities' project-related debt of \$70,490 (US \$58,718) and the repayment of the Amended Credit Facility by \$30,500 which was funded by the Offering. Cash used in financing activities included distributions to Unitholders and deferred financing charges related to the origination and structuring of the Amended Credit Facility.

The increase in cash during the twelve-month period is primarily related to the contribution from cash flow from operations at the Cogen Facilities.

The Fund expects to be able to renew or refinance its Amended Credit Facility when it comes due.

Payments Due by Period

Contractual Obligations .	Total	Less than 1 year	1 - 3 years	4 – 5 years	After 5 Years
	\$	\$	\$	\$	\$
Long-term debt	47,500	-	47,500	-	-
Exchangeab e debentures	62,295			-	62,295
Swing line of credit	1,615	1,615	-	-	-
Capital lease obligations	291	45	156	<i>7</i> 1	19
Operating leases	5,459	1,469.	2,086	1,656	248
Other long term obligation	17	1 <i>7</i>	•	-	-
Total Contractual Obligations	117,177	3,146	49,742	1,727	62,562

SUMMARY OF QUARTERLY OPERATIONAL RESULTS

	83-Day Period Ended June 30, 2004	Three-month Period Ended September 30, 2004	Three-month Period Ended December 31, 2004
	Q2		
Energy Volumes			
Sales of Steam (Mbs)	67,897	68,225	116,952
Sales of Hot Water (MMBtus)	52,976	37,520	88,286
Sales of Chilled Water (MTon/hr)	<i>7</i> 39	1,285	257
Sales of Electricity (MWh)	125	18	201
Fuel Consumed (MMBtus)	204,975	182,625	328,596
Financial Indicators	\$	\$	\$
Total Revenues	6,543	6,714	7,879
Adjusted EBITDA	3,599	3,861	3,848
Net Income	2,711	2,694	2,160
Net income per Trust Unit (whole dollars)	0.18	0.18	0.15

	Three—month Period Ended March 31, 2005	Three-month Period Ended June 30, 2005	Three-month Period Ended September 30, 2005	Three-month Period Ended December 31, 2005
	Q1			
Energy Volumes				
Sales of Steam (Mlbs)	1 <i>7</i> 1,842	<i>7</i> 2,222	180,926	240,084
Sales of Hot Water (MMBtus)	132,625	60,119	32,516	88,053
Sales of Chilled Water (MTon/hr)	136	915	1,593	268
Sales of Electricity (MWh)	292	171	133,393	103,830
Fuel Consumed (MMBtus)	436,099	223,442	1,498,207	1,887,829
Financial Indicators	\$	\$	\$	\$
Total Revenues	9,376	<i>7</i> ,189	26,754	23,842
Adjusted EBITDA	4,427	3,145	10,565	6,486
Net Income	3,020	891	5,211	4,039
Net income per Trust Unit (whole dollars)	0.20	0.06	0.35	0.24

All of the indicators outlined above have been significantly impacted by the acquisition of the Cogen Facilities beginning with Q3 of 2005. The third quarter of 2005 was the first time the Cogen Facilities' energy volumes and financial results were incorporated into those of the Fund, and the quarter included the full quarter of the Cogen Facilities' results. This makes the comparability of quarters before and after the Ripon Power acquisition on June 29, 2005 less meaningful.

District Energy System energy volumes and sales are seasonal, with a majority of energy volumes, sales and earnings occurring during the winter heating season and typically lower results during spring and fall when less heating is required by customers. Sales of steam and hot water are greatest during the winter heating season in Q1 and Q4, while sales in the summer quarters, Q2 and Q3, are much lower in terms of revenue earned. The Cogen Facilities' energy volumes and sales are also seasonal, offsetting the seasonal impact of the District Energy

Systems. The majority of the Cogen Facilities sales and earnings occur during the summer quarters, Q2 and Q3, and results are lower during the winter season when electrical capacity revenues are lower. The cyclicality of the Cogen Facilities' results are expected to have a greater overall impact on energy volumes, revenues, Adjusted EBITDA and net income than those of the District Energy Systems.

Adjusted EBITDA and net income will generally follow a seasonal pattern similar to increases and decreases in energy volume sales, although there were some anomalies in Q2 and Q3 2004, as well as Q2 2005 due to non-cash related adjustments for unrealized gains and losses on the interest rate swap and foreign exchange, write-off of deferred financing fees on the original bank credit facility and for the deferred tax treatment of some items. The results for Adjusted EBITDA and net income in the three-month period ended June 30, 2005 were significantly impacted by the expensing of Ripon Power related transaction costs of \$437 paid to the Manager, as well as the write off of \$415 in deferred financing fees also related to the Ripon Power acquisition. Excluding these transaction costs related to the Ripon Power acquisition, Adjusted EBITDA would have been \$3,997 and net income would have been \$1,743. These expenses were not related to the ongoing operations of the Fund.

Prior to the third quarter of 2005, the variance in revenue between quarterly periods was due primarily to the commencement of the winter heating season in the three-month period ended December 3.1, 2004. The Cogen Facilities contributed much of the increases in sales volumes and fuel consumed between 2004 and 2005.

FINANCIAL INSTRUMENTS

Interest Rate Swap

During December 2005 one of the Fund's indirect subsidiaries entered into an interest rate swap agreement to fix the interest rate paid on \$47,000 of its long-term debt at a current rate of 3.87%. The swap matures on June 27, 2008. The notional amount of the swap is \$47,000 and payments are due every three months. As at December 31., 2005, the fair value of the swap agreement was \$253 favourable.

Foreign Exchange

Substantially all of the District Energy System's operations and earnings are in Canadian dollars. The USEB loan is denominated in Canadian dollars and the interest is fixed at 11.0% per annum, which mitigates the foreign exchange and revenue volatility risk of the Fund, respectively. Therefore, the foreign exchange risk remains with USEB with respect to servicing the USEB Loans.

The operations and earnings of the Cogen Facilities are in US dollars. The Fund has capital-related obligations in the form of interest payments on the Debentures, as a result of the acquisition of Ripon Power. Of the annual US dollar cash flow from the Cogen Facilities that is expected to meet those obligations, approximately US \$3.400 is naturally hedged through the fixed interest coupon related to the US dollar denominated Debentures issued through Countryside Canada.

Approximately US \$5,300 of annual cash flow from the Cogen Facilities, all or a portion of which is expected to be used to meet Canadian dollar denominated debt service obligations and anticipated monthly unitholder distributions, is hedged using Canadian dollar, monthly "knockout" call option contracts which have an exercise price of US \$0.89 per Canadian dollar. The Fund has purchased thirty-six consecutive monthly call option contracts at the same exercise price until December 2008. To the extent that the US/Canadian dollar exchange rate reaches US \$0.84 (the "Knockout Price") at anytime while option contracts are still in effect, the remaining unexpired monthly call option contracts will immediately expire and be automatically replaced with a forward foreign exchange contract at an exchange rate equal to the Knockout Price with the same scheduled monthly Canadian dollar amounts and a final expiry of December 2008. When the US dollar exchange rate reaches \$0.89 or higher, the Fund has the option to exercise the call option and fix the exchange rate at \$0.84. The parameters related to the call options and currency hedge described above have the effect of limiting the Fund's risk to foreign exchange fluctuation between \$0.84 and \$0.89 on US \$5,300 annually for a three year period.

The call option contracts were entered into with a Schedule 1 bank during December of 2005 at a cost of US \$188.

RISKS AND UNCERTAINTIES

Risks Related to Operations

USEB's Renewable Projects' ability to generate and deliver to its customers electricity and biogas (as applicable) on a daily basis and at certain expected levels is the main factor in determining the cash available for payments by USEB to Countryside Canada under the USEB Loan and the USEB Royalty. Similarly the District Energy Systems' ability to deliver steam, hot water and chilled water to its customers is the main factor for determining the cash available for distribution to unitholders from such facilities. Likewise, the Cogen Facilities' ability to deliver electricity and steam to their customers is the main factor for determining cash available for distribution to unitholders from such facilities. If operations are interrupted at the Fund's operating facilities or USEB due to mechanical failure, lack of fuel supply or for other reasons, it could have a negative effect on distributable cash to unitholders.

The amount of energy produced by USEB's Renewable Projects also depends on the extraction and availability of biogas from public and privately owned landfills. The quantity of biogas available and the ability to collect it is determined by numerous factors which are beyond the control of USEB and which cannot be predicted with certainty.

Likewise, the amount of energy generated by the PEI System is dependent on the availability of a suitable supply of wood waste and municipal solid waste which may be subject to adverse change for reasons beyond the control of the Fund.

The Cogen Facilities use natural gas for fuel. The Cogen Facilities currently purchase natural gas through purchase transactions entered into pursuant to a base gas purchase agreement which expires on June 30, 2006. There can be no assurance that the Cogen Facilities will enter into new long-term gas contracts or otherwise purchase natural gas in the market at the same price as they receive today. Further, the prices which the

Cogen Facilities currently pay for natural gas correlate with the energy prices which the Cogen Facilities receive under amendments to its PPA's. Such PPA amendments expire on June 30, 2006 and the energy prices received are expected to revert to the utilities full short run avoided costs, commonly referred to as Short Run Avoided Cost or "SRAC", which currently correlate with California gas price indices. The Ripon PPA and the San Gabriel PPA do not expire until 2018 and 2016 respectively. The SRAC rates are the subject of a pending regulatory proceeding and may be modified. (See "Risks and Uncertainties - Electricity Pricing"). The Manager is attempting to negotiate new gas purchase contracts which will correlate the Cogen Facilities' future gas costs with future energy prices. In the event such negotiations are unsuccessful and the Cogen Facilities' gas costs increase without compensating adjustments in energy prices, operating margins at the Cogen Facilities may be reduced in turn reducing the Fund's distributable cash.

Electricity Pricing

While a majority of the off-takers of USEB's Renewable Projects are contractually obligated to purchase electricity under long-term PPAs, those projects based on market pricing will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term contracts terminate or expire, USEB will be required to either re-negotiate with existing off-takers, negotiate new PPAs with new off-takers, or sell electricity into the electricity wholesale market or spot market, in which case the prices for electricity will depend on prevailing market conditions. Similarly, when the USEB Renewable Projects located in Illinois are no longer eligible to receive incentives under the Illinois Public Utilities Act, it is expected that the projects will seek to negotiate new contracts in the wholesale and green power markets based on rates prevailing in those power markets at the time. Further, the Gross Price which USEB's Illinois-based Renewable Projects receive is equal to the average amount per kWh paid by the local government entities in the project's respective jurisdiction which has been subject to change and, may be subject to further change in the future.

The Cogen Facilities sell power pursuant to two long term PPAs which provide for capacity payments (which are substantially fixed) and energy payments, which generally are based on utilities' full SRAC as determined by the CPUC. Under the PPAs, the Cogen Facilities' ongoing ability to receive the full firm capacity payment and capacity bonus payments is conditioned upon the delivery of the contract capacity during on-peak hours during the summer peak months May through October for the Ripon Facility and June through September for the San Gabriel Facility subject to certain terms and conditions. Any adverse change in capacity and/or capacity bonus payments may negatively impact the Cogen Facilities' cash flow which in turn may negatively impact the Fund's distributable cash.

In 2001, the Ripon Facility and PG&E entered into a 5 year amendment of the Ripon Facility PPA which substituted a primarily fixed energy rate (subject to adjustment for time of use factors) for SRAC. When this amendment expires in July 2006, it is expected that the Ripon Facility will again receive energy payments under the Ripon Facility PPA based on PG&E's SRAC prices. The San Gabriel Facility currently receives a monthly energy payment for energy delivered to SCE in an amount calculated by reference to a SRAC pricing formula specified in the five year interim agreement of its PPA which terminates no later than July 1, 2006 ("SG Amendment"). Currently, the SRAC energy prices are based on a transition formula, which is determined separately by each utility on a monthly basis. The authority to modify the elements of the SRAC energy price formula rests with the CPUC, subject to certain statutory requirements imposed by the Electric Utility Industry Restructuring Act (Assembly Bill 1890). There is an open proceeding in which the CPUC has indicated it will review the SRAC pricing for possible prospective changes. There can be no assurance that any change in the SRAC price methodology will not adversely affect the operating margins derived by the Ripon Facility from the PPAs and, consequently, the Fund's distributable cash.

Furthermore, the Cogen Facilities' PPAs terminate in 2018 (Ripon) and 2016 (San Gabriel). There is no assurance that upon expiry of such PPAs, the Fund's subsidiaries will be able to enter into new PPAs or otherwise sell their power into the market at prices at or above projected levels. Future prices and rates cannot be predicted with certainty and will inevitably deviate from such forecasts and such deviation may be material.

Significant declines in prices and rates would be expected to have a material adverse impact on USEB and/or Cogen Facilities as applicable. While the Manager believes that strategies exist to mitigate, at least in part, the adverse effects of such price declines, there is no assurance such strategies will be available or implemented successfully.

Foreign Currency Fluctuations

A majority of the Fund's costs and its financial obligations to its lenders and unitholders are denominated in Canadian dollars. It's obligation to Debenture holders is denominated in US dollars.

The USEB Loan is denominated in Canadian dollars, requiring USEB to make payments on the USEB Loan in Canadian dollars. Because USEB is exposed to currency exchange rate risk as a result of the loans, the loan documents require USEB to enter into currency hedge agreements during the entire term of the loan to mitigate the risk posed by the currency transaction risk into Canadian dollars. To the extent that USEB's ability to satisfy its obligations under the USEB Loan is affected by an unfavorable exchange rate or an inability to maintain hedging arrangements in the future, the Fund's ability to pay cash distributions to unitholders may also be affected.

The Cogen Facilities' revenues derived from PPAs and steam sale agreements are denominated in US dollars as is the expected resultant US dollar denominated distributable cash from the Cogen Facilities. The Manager has entered into a foreign exchange option to mitigate the effect of the resultant foreign exchange risk related to the portion of US dollar revenues required to meet its Canadian dollar obligations and anticipated unitholder distributions as outlined under the section "Financial Instruments".

Interest Rate and Debt Repayment Risk

At present, the Fund's Amended Credit Facility bears interest at a variable rate based on short-term Canadian banker's acceptances and Canadian prime rates. An increase in short-term interest rates, if unhedged, could affect the Fund's ability to pay interest on outstanding balances under the Amended Credit Facility and distributions to unitholders. To mitigate this interest rate risk, the Fund has entered into an interest rate swap agreement, which sets the base interest rate at a fixed coupon for a portion of the balance and term of the loan.

The Fund has approximately US \$55,000 of Debentures outstanding which bear interest at a fixed coupon rate of 6.25% and are payable in US dollars. A decrease in revenues earned or an increase in expenses incurred by the Cogen Facilities could affect the Fund's ability to pay interest to holders of the Debentures.

With regard to debt repayment risk, there can be no assurance that the Fund will have sufficient capital or be successful in refinancing the Amended Credit Facility or the Debentures when they mature.

Tax Risk

There is no guarantee that Canadian or U.S. tax legislation and treatment of mutual fund trusts will not change in such a way as to adversely affect distributions to unitholders. For example, if U.S. tax legislation were to change adversely or U.S. tax authorities to challenge how USEB or Countryside US Holding treats certain tax deductions when calculating its taxable income, the payments received by the Fund's Canadian subsidiaries from USEB and Countryside US Holding could be reduced.

In addition, USEB currently receives income from the sale of the United States Internal Revenue Code of 1986, as amended (the "Code") Section 29 tax credits which will expire on December 31, 2007 unless the law is extended. Through December 31, 2007, Code Section 29 has a phase out provision that is triggered when the "Market Wellhead Price" of domestic crude oil reaches certain "Phase-out Prices" as determined by the Internal Revenue Service ("IRS"). The phase-out is proportional. Due to the recent spike in oil prices, Market Wellhead Prices

in 2005 have, on occasion, exceeded the price at which the Phase out would be triggered. Nevertheless, based on average Market Wellhead Prices for 2005 and estimates of 2005 Phase-out Prices, the Manager believes that the Phase-out will not be triggered in 2005. However, there can be no assurance that future oil prices will remain under future phase out levels in 2006 and 2007. If a phase out is triggered during such years or in 2005, USEB's income from Code Section 29 tax credits may be reduced or eliminated, thus reducing cash available for servicing debt service on the USEB Loan and for payments of the royalty.

Regulatory and Legislative Risk

The Fund's District Energy Systems, USEB's Renewable Projects and the Cogen Facilities must be licensed to comply with energy, operational, environmental, and safety statutes, standards, orders and regulations enacted by legislative bodies and imposed by regulatory bodies. Although the Fund believes that all such facilities are in compliance in all material respects with such statutes, permits, standards, orders and regulations, failure to operate the facilities in compliance with such statutes, permits, standards, orders and regulations may require temporary or permanent cessation of operations of the facilities and may expose owners and operators to claims and clean-up costs. Any new law or regulation could require significant new expenditures to achieve or maintain compliance.

Qualifying Facility and Qualifying Solid Waste Energy Facility Status

The Cogen Facilities and the majority of USEB's facilities are QFs under the Public Utilities Act of 1978 as amended ("PURPA") as implemented by the Federal Energy Regulatory Commission ("FERC"). Loss of QF status could trigger defaults under covenants to maintain QF status under the PPAs and debt agreements (including in the case of USEB's facilities, the USEB Loan) and result in PPA termination, penalties or acceleration of indebtedness under such agreements plus interest. Further, under PURPA, a regulated utility could refuse to purchase electricity from the facility(ies) at such utility's avoided cost if QF status were lost and may be entitled to certain remedies for breach

of an existing PPA including the right to terminate the PPA. In addition, the FERC has asserted jurisdiction over the rates charged by QFs during periods when a facility does not operate in compliance with the applicable OF criteria and has indicated its willingness to order the refund of payments previously made under PPAs in some cases. Further, loss of QF status could expose either Facility to regulation by FERC under the Federal Power Act, by the CPUC and, until February 8, 2006, by the Securities and Exchange Commission under the Public Utility Holding Company Act. Additionally if one of USEB's Illinois facilities lost QF status, it may lose QSW status (as defined below) under the Illinois Public Utilities Act.

Any of these consequences would result in substantial regulatory burdens, potentially lower revenues from power sales and potentially insurmountable impediments to affected entities with regard to conducting business in the manner currently contemplated. Accordingly, the Cogen Facilities ability to generate distributable cash as well as the ability of USEB's facilities to generate cash to service the USEB Loan and make payments under the USEB Royalty is dependent on their maintaining QF status. A facility may lose its QF status either temporarily or permanently.

On August 8, 2005, comprehensive energy legislation was enacted when the President of the United States signed into law EPA 2005, including several changes to PURPA. On February 2, 2006, the FERC issued its Order No. 671 promulgating new regulations to reflect the changes in PURPA made by EPA 2005.

Most of the changes to PURPA made by EPA 2005 and the FERC's Order No. 671 will apply only to new cogeneration facilities and, therefore, will not affect the Cogen Facilities or USEB's facilities at least for as long as the thermal output of the facilities is sold to the existing steam hosts. If any such facilities should lose QF status and if it should be determined that the purchasing utility has the right to terminate its PPA as a result thereof, the provisions of EPA 2005 and the new FERC regulations promulgated there under may apply to any new

PPA entered into under PURPA for any of the facilities. In Order No. 671, the FERC eliminated the exemption from rate regulations under Sections 205 and 206 of the Federal Power Act for sales of electricity made by qualifying facilities other than pursuant to a State regulatory authority's implementation of PURPA. As a result, should electricity be sold from either of the Cogen Facilities other than pursuant to their existing PPAs, the contract or tariff pursuant to which the electricity is sold will have to be filed with, and accepted for filing by, the FERC.

Certain of USEB's Renewable Projects in Illinois receive certain benefits and exemptions because each is a Qualified Solid Waste Energy Facility ("QSW Status") under the Retail Rate Law of the Illinois Public Utilities Act (the "Retail Rate Law"). If any of USEB's Illinois Renewable Projects were to lose its QSW status, the facility would no longer be entitled to the benefits of the Retail Rate Law. In such event the applicable Illinois utility may no longer be required to purchase electricity from the relevant projects at the rates provided for in the Retail Rate Law. Under certain circumstances, loss of QFW Status on a retroactive basis could lead to, among other things, claims by the utility customers for a refund of payments already made.

Further, such facilities may lose all or some of such benefits if PURPA or the Illinois Public Utilities Act (or the regulations or orders promulgated there under) were repealed or modified or if any court or regulatory body adopted a new interpretation of such statute, regulation or order. From time to time, legislation modifying the Illinois Public Utility Act has been proposed. If certain of the introduced legislation had been enacted in its proposed form, it would. reasonably be expected to have a material adverse effect on the QSWEFS. To date such legislation has not been enacted; however there can be no assurance that such legislation will not be enacted in the future. Any of these events could have a material adverse effect on USEB's ability to make payments to the Fund's Canadian subsidiary under the USEB Loan or USEB Royalty.

Potential Cogen Facilities' Refund Liability

A proceeding is currently pending before the CPUC in Docket No. R 99-11-022 in which the CPUC is considering whether to apply retroactively for the period December, 2000 through March, 2001 a March, 2001 decision (D. 01-03-067) which, among other things, modified the methodology used in calculating SRAC and thereby decreased SRAC levels for the period commencing March 27, 2001. In September, 2002, the California Court of Appeals found that the CPUC had violated PURPA for failing to consider SCE's argument that the CPUC should retroactively apply the modified SRAC formula. Southern Cal. Edison vs. Public Utilities Comm'n., 101 Cal. App. 4th 982 (2002). The Court of Appeals directed the CPUC to consider SCE's request. In February, 2005, a Draft Decision was issued by the assigned Commissioner who found that "evidence shows SRAC prices were correct between December 2000 and March 2001, and retroactive application of the modified SRAC formula is not warranted". Various parties have submitted comments on the Draft Decision, including PG&E, SCE, a ratepayer organization and the CPUC's Office of Ratepayer Advocates, objecting to the Draft Decision. The CPUC has not yet issued a final decision in the matter and is free to accept the Draft Decision as written, modify it or reject it in its entirety. The outcome of this proceeding cannot be predicted. Even in the event of an adverse CPUC decision, the Manager has been advised by counsel that the Cogen Facilities would have several meritorious legal defenses that would be available to protect the Cogen Facilities from any material adverse impact. However, there is no assurance that the Cogen Facilities would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal or otherwise enjoined, QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could materially and adversely affect the Cogen Facilities' ability to generate distributable cash.

Potential Cogen Facilities' Steam Host Termination for Convenience

Both steam hosts at the Cogen Facilities are permitted to terminate their respective steam sales agreements for convenience under certain circumstances. Each steam sales agreement provides that, in such event, the steam customer must make a specific monetary payment to the Cogen Facilities to cover their cost of obtaining a replacement steam host. The San Gabriel Facility's steam host's obligation to make such payment terminates after the twelfth year of the steam sale agreement. Such steam host may also discharge its obligation by obtaining a replacement steam host. It is possible that either steam host may exercise such termination right but fail to comply with its obligations to obtain or fund the cost to obtain a replacement steam host due to lack of resources or for other reasons. In such event the Cogen Facilities may not have an adequate remedy against the steam host and be required to obtain a replacement steam host at its own expense or probably lose its QF status. Loss of QF Status would have a material adverse effect on the Cogen Facilities. See "Risk and Uncertainties" - Qualifying Facility and Qualifying Solid Waste Energy Facility Status".

Reliance on Third Parties and Potential Conflicts of Interest

Pursuant to the Management Agreement and the Administration Agreement, commencing on November 1, 2005 the Fund and its subsidiaries will rely substantially on the Manager and its Canadian subsidiary for management, administration and project development functions. (See "Transactions with Related Parties - Management Agreement and Administration Agreement"). There may be circumstances in which the interests of the Manager, its affiliates or entities managed by such parties may conflict with those of the Fund, Countryside Canada, its subsidiaries and the Unitholders. Although the Manager's senior executives are required to devote a significant majority of their time for the benefit of Countryside Canada, Countryside US Holdings and its subsidiaries and to the development of projects reasonably expected to be

within the acquisition criteria of the Fund, the Manager's personnel are not required to devote their time exclusively to these activities. Further, while the Manager is prohibited from providing management and administrative services to third parties other than the Fund, the Manager may develop and own energy and utility infrastructure projects for its own account or jointly with third parties, subject to its obligation to provide the Fund with a first opportunity to invest in such projects. Thus, subject to the constraints described above, the Manager and its senior executives may engage in activities similar to the current activities of the Fund, Countryside Canada and its subsidiaries.

The Manager and its affiliates, however, will provide Countryside Canada and its subsidiaries with the first opportunity to invest in any entity or asset that meets the investment criteria of the Fund and Countryside Canada that the Manager or its affiliates develop, own or control. The Manager shall only be free to offer such investment opportunities to third parties or to pursue them for its own account if Countryside Canada or its subsidiaries decline or are unable to pursue such opportunities.

Circumstances may arise where the Fund trustees or members of the board of directors of a corporation in which the Fund has invested are directors or officers of corporations that compete with the interests of the Fund. No assurances can be given that opportunities identified by such persons will be provided to the Fund or an entity in which the Fund has invested.

Further provisions in the Declaration of Trust, which are similar to those contained in the Canada Business Corporations Act, provide certain procedures to be followed in the event of such conflicts of interests, and certain remedies may be available to the Fund where such procedures are not followed.

The Fund is reliant upon USEB with respect to the administration and operations management of the USEB Renewable Projects. The Cogen Facilities are partially reliant on independent contractors for the day to day operational and asset management of the facilities.

The Fund's business risks remained substantially unchanged since December 31, 2004 except for the addition of the Cogen Facilities' related issues.

Other Risks

For a more detailed discussion of risk factors, reference should be made to the 2004 Annual Information Form, as well as the Prospectus of the Fund and Countryside Canada filed with securities regulators on November 8, 2005 pages 55 to 65 which are incorporated by reference and filed on www.sedar.com.

TRANSACTIONS WITH RELATED PARTIES

Development Agreement with Cinergy and USEY

Countryside U.S. Power Inc. ("Countryside U.S. Power"), a subsidiary of Countryside Canada, has entered into a Development Agreement with an indirect subsidiary of Cinergy and USEY under which, subject to its terms and conditions, the Cinergy subsidiary and USEY will contribute their experience and financial resources to the acquisition, development, improvement and operation of energy projects that they choose to pursue and that will meet the Fund's investment and growth objectives. Countryside U.S. Power, through service provided by Countryside Ventures, provides investment analysis and evaluation services on behalf of all parties to the agreement. In consideration for these services, Countryside U.S. Power shall be paid an annual fee of approximately US \$440 for 2005 from an indirect subsidiary of Cinergy and USEY.

Commencing in May 2005, USEY ceased monthly fee payments. Countryside US Power and USEY are in discussions concerning USEY's obligations under the Development Agreement to determine a possible resolution. The Development Agreement has an initial term of five years and will be automatically renewed for an additional five-year term unless terminated by any party.

Independence Power LLC

On June 29, 2005, Countryside US Holding, an indirect subsidiary of the Fund, paid \$437 to Independence Power LLC in consideration for services performed by Independence for Countryside US Holding in connection with the origination and structuring of the acquisition of Ripon Power. Independence changed its name to Countryside Ventures LLC ("Countryside Ventures") on September 19, 2005. Countryside Ventures is controlled by members of senior management of the Fund who serve as officers and directors of certain Fund subsidiaries including Countryside US Holding. Such payment was approved by the Joint Compensation and Corporate Governance Committee of the Fund and Countryside Carlada based, in part, on an opinion from an independent financial advisor that the payment was fair.

Management Agreement

On September 23, 2005, Countryside US Holding and Countryside Canada entered into the Management Agreement with Countryside Ventures as outlined above under "Overview of Fund and Recent Developments – Recent Developments – Increase in Unitholder Distributions and Management Agreement". During 2005, a total of \$805 was paid to Countryside Ventures related to the short term incentive plan and reimbursement of costs pursuant to the Management Agreement.

Administration Agreement

On September 26, 2005 the Fund and Countryside U.S. Power entered into a Management and Administration Agreement ("Administration Agreement") with Countryside Canaca Ventures Inc. ("Countryside Ventures Canada"), which is a wholly owned subsidiary of Countryside Ventures. Under the Administration Agreement, effective November 1, 2005, Countryside Ventures Canada commenced, providing management and administrative services to the Fund and Countryside Canada. In carrying out the services described above, Countryside Ventures Canada and its affiliates will be entitled to reimbursement from the Fund and Countryside Canada of all costs and expenses incurred in connection therewith. During 2005, a total of nil was paid to Countryside Ventures Canada.

Operating Agreement

As provided for in the Management Agreement, Countryside US Holding and Countryside Ventures entered into an Operating Agreement on November 3, 2005 respecting Ripon Power which was effective as of July 1, 2005. This agreement will implement for the Ripon Power acquisition, the long-term incentive plan provided for in the Management Agreement. Under the terms of the Operating Agreement, Countryside US Holding will hold a preferred membership interest (the "Preferred Interest") entitling it to preferred distributions of "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Operating Agreement. Countryside US Holding and Countryside Ventures will, hold subordinate membership interests ("the "Subordinate Interests") entitling them to residual distributions made to members, after distributions made in respect of the Preferred Interest, in a ratio of 75:25. Countryside Ventures' Subordinate Interest distribution is subject to downward adjustment and mutual exchange rights as provided in the Management Agreement. During 2005, a total of \$1,515 was paid to Countryside Ventures pursuant to the Operating Agreement related to its Subordinated Interest.

CONTROLS AND PROCEDURES

As of December 31, 2005, an evaluation was carried out, under the supervision of and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the Fund's disclosure controls and procedures as defined under Multilateral Instrument 52-109. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective. Except for the impact of the Ripon Power acquisition, no changes were made in the Fund's internal control over financial reporting during the year ended December 31, 2005, that have materially affected, or are reasonably likely to materially affect, the Fund's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Fund's consolidated financial statements requires the Manager to make estimates and judgments as they relate to matters that are inherently uncertain. Changes in these judgments or estimates could have a significant impact on the Fund's consolidated financial statements. The Manager believes that the following critical accounting estimates involve the more significant estimates and judgments used in the preparation of our annual consolidated financial statements.

Power Purchase Agreements

Power purchase agreements ("PPAs") were recorded at their fair values at the time of the purchase of Ripon Power. The fair value of the intangible asset balance is being amortized over the life of the PPAs expiring in 2016 & 2018.

Customer Relationships

Customer relationships were recorded at their fair values at the time of the acquisition of the District Energy Systems. The fair value of the customer relationships balance is being amortized over 21 years on a straight-line basis. The Manager has used judgment and estimates in determining the appropriate amortization period giving consideration to both the historical performance of customer renewals and the useful life of the energy service agreements in place at the time of the acquisition of the District Energy Systems by the Fund.

USEB Loan Receivable

The Fund receives interest income and principal repayments in connection with their loan to USEB. The Manager continually monitors the future expectations of cash receipts from the loan and the value of the outstanding principal by assessing USEB's cash flow generating capability and reviewing major cash flow factors such as production volume, operating costs and maintenance expenses. Consideration is given as to whether a decline in recent or future cash flow is regarded as continuing for an extended period of time or is temporary. Should cash flow be insufficient to service the loan obligation and the deficiency is regarded as permanent, the loan is considered impaired and a charge for impairment must be recognized. The charge taken will represent the reduced loan principal required to ensure that loan obligations can be met. It is the view of the Manager that there has been no impairment in these loans in 2005.

OUTLOOK

The Fund anticipates that unitholder cash distributions will continue at \$1.035 per unit for the remainder of fiscal 2006. During the course of 2006, the Fund will reassess the level of its unitholder distributions for possible increases after it determines the impact, if any, of the SRAC proceeding before the California Public Utility Commission as it relates to energy payments received under the power purchase agreements and the negotiations on final terms and conditions of new fuel supply arrangements for the Cogen Facilities.

Operations

The District Energy Systems and Cogen Facilities are not expected to have any significant capital expenditures in fiscal 2006 outside of normal operating maintenance capital expenditures. Major maintenance or overhaul on major gas turbine equipment for both the Ripon Facility and San Gabriel Facility is scheduled for 2007 and 2008, respectively. The Fund anticipates the cost of such major maintenance to be paid through either cash reserves held back from operations or through funds drawn under its unutilized credit facility. The District Energy Facilities have completed major efficiency and extended life improvements. No scheduled major maintenance is planned to be undertaken for the next few years.

Growth

The Manager, on behalf of the Fund, intends to evaluate the Fund's potential participation in a request for proposals presently being conducted by the Ontario Power Authority ("OPA") seeking to solicit up to 1,000 megawatts of combined heat and power generation in the Province of Ontario. The Fund's London, Ontario based district energy facility already operates in this market and may be able to meet the criteria for providing a portion of the requested power generation. The Manager will evaluate if an expansion of the London System's power generating capability and terms of a concomitant new power purchase agreement with OPA would be competitive in the market and economically beneficial to the Fund, as well as accretive to the Fund's distributable cash. If the Fund's independent board of trustees deems

such participation advisable, the Manager will prepare and submit a formal proposal on behalf of the Fund in response to the OPA's request. The OPA's decision for awarding a new power contract under its solicitation process will likely be ongoing through 2006 and its final outcome cannot be predicted at this time by the Fund or the Manager.

The Manager, on behalf of the Fund, is also evaluating the economic benefits of expanding the Cogen Facilities' power generating capability with the aim of selling additional electrical capacity and energy to local customers in the California market. The fundamentals for power demand growth remain sound in California. The Manager believes that the California power market will also provide other opportunities for power generation acquisitions similar to the Ripon Power acquisition as non-strategic players continue to divest assets.

We are committed to growing the Fund through accretive investments. We have a disciplined investment strategy to identify and pursue acquisitions and investment opportunities. Our dynamic industry has been undergoing a shift in the ownership of unregulated generation assets, which offers a number of consolidation and partnership prospects for Countryside. Further, there appears to be growing support for renewable power generation from both government and industry in light of Canada's commitment to the Kyoto Protocol and the U.S. market trend to energy independence as a result of rising oil and natural gas prices. Countryside is actively evaluating opportunities in power generation and utility infrastructure, with a view to increasing unitholder value and growing distributions.

MANAGEMENT'S responsibility report

The accompanying donsolidated financial statements of Countryside Power Income Fund were prepared by management, which is responsible for the integrity and fairness of the information presented, including the amounts based on estimates and judgments. These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles. Financial information appearing throughout this Annual Report is consistent with these consolidated financial statements.

In discharging its responsibility for the integrity and fairness of the consolidated financial statements and for the accounting systems from which they are derived, management maintains internal controls designed to ensure that transactions are authorized, assets are safeguarded and proper records are maintained.

The Board of Trustees oversees management's responsibilities for financial reporting through a Joint Audit Committee. This Joint Committee reviews the consolidated financial statements of the Fund and recommends them to the Board for approval.

Ernst & Young, independent auditors appointed by the unitholders of the Fund upon the recommendation of the Audit Committee, have performed an independent audit of the consolidated financial statements, and their report follows. The unitholders' auditors have full and unrestricted access to the Joint Audit Committee to discuss their audit and related findings.

Göran Mörnhed President and Chief Executive Officer Countryside Ventures LLC Edward M. Campana

Executive Vice President & Chief Financial Officer

Countryside Ventures LLC

AUDITORS' report

To the Unitholders of Country side Power Income Land

We have audited the consolidated balance sheets of Countryside Power Income Fund as at December 31, 2005 and 2004 and the consolidated statements of income and deficit and cash flows for the year ended December 31, 2005 and for the period from February 16, 2004 to December 31, 2004. These financial statements are the responsibility of management of the Fund. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2005 and December 31, 2004 and the results of its operations and its cash flows for the year ended December 31, 2005 and for the period from February 16, 2004 to December 31, 2004 in accordance with Canadian generally accepted accounting principles.

Toronto, Canada, March 9, 2006. Ernst . young LLP

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 [in thousands of Canadian dollars]

	2005	2004
	\$	\$
ASSETS		
Current		
Cash and cash equivalents	10,312	3,035
Accounts receivable [note 15]	13,025	3,227
Inventories [rote 6]	1,310	1,054
Prepaid expenses	1,226	1 <i>7</i> 0
Current portion of loans receivable from U.S. Energy Biogas Corp. [note 7]	2,040	1,828
Total current assets	27,913	9,314
Loans receiváble from U.S. Energy Biogas Corp. [note 7]	101,921	103,961
Royalty interest in U.S. Energy Biogas Corp., net [note 8]	7,194	7,588
Other assets [note 9]	6,894	1,982
Property, plant and equipment, net [note 10].	72,807	30,663
Other intangibles, net [note 11]	75,078	12,609
Total assets	291,807	166,117
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Bank indebtedness [note 12]	1,615	-
Accounts payable and accrued liabilities	7,909	1,630
Distributions payable [note 18]	1,694	1,274
Total current liabilities	11,218	2,904
Long-term debt [note 12]	47,500	30,000
Debentures - liability component [note 5]	62,295	-
Other liabilities	336	1 <i>77</i>
Future income tax liability [note 13]	1,591	282
Total liabilities	122,940	33,363
Commitments and contingencies [note 16]		
Unitholders' equity		
Trust units [notes 3, 5 & 14]	177,505	136,350
Debentures – equity component [note 5]	1,715	-
Deficit	(6,580)	(3,596)
Cumulative translation adjustment	(3,773)	,
Total unitholders' equity	168,867	132,754
Total liabilities and unitholders' equity	291,807	166,117

See accompanying notes

Approved on behalf of Countryside Power Income Fund:

V. James Sardo Chairman of the Board Countryside Power Income Fund

James R. Anderson Trustee Countryside Power Income Fund

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CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

[in thousands of Canadian dollars, except per trust unit amounts]

	For the year ended December 31, 2005	For the period from February 16, 2004 to December 31, 2004
	\$	\$
REVENUES		
Energy sales	52,823	10,466
Fuel and other fees	2,252	1,679
Interest income on loans to U.S. Energy Biogas Corp. [note 7]	11,546	8,556
Income from U.S. Energy Biogas Corp. royalty interest [note 8]	369	410
Other income	171	25
	67,161	21,136
EXPENSES		
Fuel, operating and maintenance	34,898	7,775
General and administration [note 20]	7,753	2,053
Depreciation and amortization	8,061	1,986
	50,712	11,814
Operating income	16,449	9,322
Interest expense [note 12]	5,578	1,181
Unrealized loss (gain) on interest rate swaps [note 12]	(312)	60
Realized gain on interest rate swap [note 12]	(2,559)	-
Unrealized gain on foreign exchange	(750)	
	1,957	1,241
Income before provision for income taxes	14,492	8,081
Provision for income taxes [note 13]		
Current	22	10
Future	1,309	506
	1,331	516
Net income for the period	13,161	7,565
Deficit, beginning of period	(3,596)	-
Distributions declared to Unitholders [note 18]	(16,145)	(11,161)
Deficit, end of period	(6,580)	(3,596)
Net income per trust unit – basic [note 14]	0.85	0.51
Net income per trust unit - diluted [note 14]	0.84	0.51

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

[in thousands of Canadian dollars]

	For the year ended December 31, 2005	For the period from February 16, 2004 to December 31, 2004
	\$	S
OPERATING ACTIVITIES		
	10 141	7 545
Net income for the period Add (deduct) items not involving cash	13,161	7,565
Depreciation and amortization	7 201	988
Amortization of deferred financing charges	7,221 840	998 998
Unrealized loss (gain) on interest rate swap [note 12] Realized gain on interest rate swap [note 12]	(312)	60
Provision for future income taxes [note 13]	1,309	506
•		300
Unrealized gain on foreign exchange	(750)	-
Accreted interest on Debentures [note 5]	24	
	18,934	10,117
Net change in non-cash working capital balances related to operations	(2,393)	[1,409]
Cash provided by operating activities	16,541	8,708
INVESTING ACTIVITIES		
Acquisition of Ripon Power LLC [note 4]	(42,803)	_
Repayment of loans receivable from U.S. Energy Biogas Corp. [note 7]	1,828	1,211
Purchase of property, plant and equipment	(855)	(1,799)
Origination fee on loans to U.S. Energy Biogas Corp. [note 3]	(022)	
	-	(1,340
Acquisition of loans and funding of advances to U.S. Energy Biogas Corp. [note 3]	=	(107,000
Acquisition of U.S. Energy Biogas Corp. royalty interest [note 3] Acquisition of USE Canada Holdings Corp. [note 3]	-	(7,884
Cash used in investing activities	(41,830)	(16,241)
Cush used in investing activities	[41,630]	(133,033)
FINANCING ACTIVITIES		
Acquisition of loan and working capital revolver from Union Bank of California, [note 12]	(70,490)	•
Issuance of Debentures [note 5]	64,180	
Deferred financing charges on Debentures [note 5]	(3,922)	-
Acquisition of foreign exchange option fee [note 15]	(219)	-
Payment of swap breakage fee [note 12]	(496)	-
Proceeds from Amended Credit Facility [note 12]	48,000	30,400
Repayment of Amended Credit Facility [note 12]	(30,500)	(400
Proceeds from swing line credit facility [note 12]	1,615	-
Deferred financing charges on Amended Credit Facility [notes 12]	(1,001)	(675)
Repayment of obligations under capital lease	(31)	(23)
Distributions to Unitholders [note 18]	(15,725)	(9,887
Issuance of Trust Units on Offering [notes 3, 5 & 14]	44,132	149,054
Expenses of Offering [notes 3, 5 & 14]	(2,977)	(12,704)
Repayment of loan to US Energy Systems Inc. [note 3]		(2,396)
Repayment of USE Canada Energy Corp. Credit Facility [note 3]	-	(25,989)
Cash provided by financing activities	32,566	127,380
Nea in contract during a six d	- Aww	2.025
Net increase in cash during period Cash and each acquirelests, beginning of pariod	7,277	3,035
Cash and cash equivalents, beginning of period	3,035	3 035
Cash and cash equivalents, end of period	10,312	3,035
Supplemental cash flow information		
Interest paid	6,235	1,156
	5	

See accompanying notes

NOTE 1 - DESCRIPTION OF BUSINESS

Countryside Power Income Fund (the "Fund") is an unincorporated, open-ended, limited purpose trust established under the laws of the Province of Ontario on February 16, 2004. The Declaration of Trust was amended and restated on April 8, 2004, the date of the initial public offering of trust units of the Fund (the "Initial Offering"). The Fund owns 100% of Countryside Canada Power Inc. ("Countryside Canada".)

The Fund was established to fund, through Countryside Canada, the acquisition of Countryside District Energy Holdings Corp. (formerly known as USE Canada Holdings Corp.) consisting of the district energy systems located in Charlottetown, Prince Edward Island (the "PEI System") and London, Ontario, (the "London System"), (collectively the "District Energy Systems"), the acquisition and amendment of existing loans to U.S. Energy Biogas Corp. ("USEB"), the funding of additional advances to USEB (collectively, the "USEB Loans") and the acquisition of a convertible royalty interest in USEB (the "USEB Royalty Interest").

On June 29, 2005, the Fund completed the acquisition of the membership interests of Ripon Power LLC ("Ripon Power") (formerly known as Lightyear Rockland Partners LLC) whose principal assets are two gas-fired cogeneration facilities located in California (the "Cogen Facilities").

NOTE 2 - SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements of the Fund have been prepared by management using Canadian generally accepted accounting principles ("GAAP") and within the framework of the significant accounting policies summarized below.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and these accompanying notes. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies. Actual results could differ from those estimates.

(a) Basis of Presentation

Although the Fund was created on February 16, 2004, it did not commence operations and was essentially dormant prior to the completion of the initial public offering on April 8, 2004. As a result, the comparative statements of income and cash flows have been presented for the period from February 16 to December 31, 2004, but only reflect operating results for the period from April 8, 2004 to December 31, 2004. The results of Ripon Power's operations have been reflected in the consolidated financial statements of the Fund beginning on June 30, 2005.

(b) Basis of Consolidation

The consolidated financial statements of the Fund include the accounts of its wholly-owned subsidiary, Countryside Canada, and the accounts of Countryside Canada's direct and indirect subsidiary entities including Countryside U.S. Power Inc. ("Countryside U.S. Power"), Countryside US Holding Corp. ("Countryside US Holding"), Ripon Power, Ripon Cogeneration LLC ("Ripon Cogen"), Countryside Canada Acquisition Inc. ("Countryside Acquisition"), Countryside District Energy Holdings Corp. ("Countryside District Energy Holdings") and Countryside District Energy Corp.) (formerly known as USE Canada Energy Corp.) Countryside District Energy Holdings Corp. is the legal entity that holds the District Energy Systems. All inter-entity transactions and balances have been eliminated on consolidation.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(d) Cash and Equivalents

Cash and cash equivalents comprise only highly liquid investments with original maturities of 90 days or less and are recorded at cost, which approximates market value.

(e) Inventories

Inventories of spare and replacement parts and supplies are valued at the lower of cost, on a first-in, first-out basis, and net replacement value. Fuel, consisting primarily of natural gas, wood chips and oil, is carried at the lower of cost, as determined on a weighted average basis, or net realizable value.

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(f) Royalty Interest in U.S. Energy Biogas Corp.

The Royalty Interest in USEB is being amortized on a straight-line basis over 20 years [note 8].

(g) Property, Plant and Equipment

Capital assets are accounted for at their acquisition cost. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. The cost of the property, plant and equipment, less estimated residual value, is depreciated and amortized on a straight-line basis over the estimated useful lives of the assets as follows:

	Years
Buildings	21-35
Equipment	
Plant and distribution	1-35
Computers	3-5
Office	3-5
Vehicles	. 5
Equipment under capital lease	20

Assets included in construction in progress are not amortized until the installation of the assets is complete and the assets have entered into commercial operation.

(h) Other Intangibles

The fair values at the date of acquisition of the District Energy Systems' customer relationships are being amortized on a straight-line basis over 21 years [note 11]. The fair values of the power purchase agreements at the date of acquisition of the Cogen Facilities are being amortized on a straight-line basis over their remaining lives of between 10 and 12.5 years [note 11].

(i) Foreign Currency Translation

The assets and liabilities of the Fund's US subsidiaries having a functional currency of US dollars are translated into Canadian dollars using the exchange rate in effect at the period end and revenues and expenses are translated at the average rate during the period. Exchange gains or losses on translation of the Fund's net investment in these operations are recorded as a separate component of Unitholders' Equity.

(j) Financial Instruments

The Fund uses an interest rate swap contract to manage interest rate risk. Payments and receipts under the interest rate swap contract are recognized as adjustments to interest expense on an accrual basis. Any resulting carrying amounts are included in other assets in the case of favourable contracts and accounts payable and accrued liabilities in the case of unfavourable contracts.

Realized gains and losses on interest rate swaps are reported as a component of consolidated interest expense. The change in fair value of the interest rate swaps are recorded as an unrealized gain/loss on the statements of income and recorded as a non-current asset or liability.

The Fund has entered into call option contracts to manage its foreign exchange exposure resulting from foreign exchange fluctuations. The cost of the options was expensed with the fair value of the option contracts being recorded in other assets in the case of favourable contracts or accounts payable and accrued liabilities in the case of unfavourable contracts at the end of each reporting period [note 9].

The above derivative financial instruments represent economic hedges of known exposures, however they do not qualify for hedge accounting and therefore have been recorded at their fair value in the consolidated financial statements.

The Fund does not engage in trading or other speculative activities with respect to derivative financial instruments. The fair value of derivative financial instruments reflects the estimated amount that the Fund would have been required to pay if forced to settle all unfavourable contracts or the amount that would be received if forced to settle all favourable contracts at year end. The fair value represents a point-in-time estimate that may not be relevant in predicting the Fund's future earnings or cash flows.

The Fund is exposed to credit risk in the event of non-performance by its counterparties. The Fund does not anticipate non-performance, as the counterparty to each of the interest rate swap and the call option have investment grade credit ratings from Standard and Poor's of A+.

(k) Deferred Financing Charges

Deferred financing charges represent fees incurred related to bank financing and cebenture issuances and are being amortized on a straight-line basis over the life of the instruments, respectively [note 9].

(I) Loan Origination Fees

Loan origination fees represent costs incurred related to the USEB Loans (as defined in the USEB Loan Agreement). These costs are being amortized on a straight-line basis over 15 years [note 9].

(m) Revenue Recognition

Revenue derived from the sale of energy in the form of electricity, steam, hot water and chilled water is recognized on the accrual basis upon delivery at rates pursuant to the relevant energy service agreements ("ESAs") with the purchasing customers. In addition to the sale of energy under the ESAs, the Fund receives from the purchasing customers monthly capacity payments that are fixed and are not dependent upon the amount of energy delivered to its customers. This revenue is recognized as earned on a monthly basis. Income earned from receipt of waste fuel for the PEI System is based on long-term contracts and is recognized upon receipt of the waste fuel at the PEI System. Income from the USEB Loans and the USEB Royalty Interest is recognized as earned.

(n) Income Taxes

Future income taxes and liabilities are recognized for the future income tax consequences attributable to differences between the tax and accounting bases of assets and liabilities, as well as for the benefit of tax losses available to be carried forward to future years that are more likely than not to be realized. The differences are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

To the extent that the Fund's taxable income and taxable capital gains are paid or payable to Unitholders, under the terms of the *Income Tax Act (Canada)*, the Fund, excluding its corporate subsidiaries, is not subject to income taxes. In addition, as the Fund is contractually committed to distribute to Unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable to the Fund, the Fund is not required to apply the recommendations of the Canadian Institute of Chartered Accountants Handbook ("CICA"), section 3465. Accordingly, no provision for current income taxes for the Fund is made. Distributions may however be taxable in the hands of Unitholders.

Each of the Fund's Canadian subsidiaries are subject to corporate income and capital taxes as computed under the Income Tax Act (Canada) and relevant provincial tax legislation and to CICA Handbook section 3465. Each of the Funds' U.S. subsidiaries are subject to corporate and state revenue and franchise taxes as well as withholding tax on interest and dividends paid to Canadian corporations. A valuation allowance is provided to the extent that it is more likely than not that future income tax assets will not be realized.

(o) Net Income per Trust Unit

Net income per Trust Unit is based on the consolidated net income for the period, divided by the weighted average number of Trust Units outstanding during the year which was 15,513,147 (from April 8 to December 31, 2004 – 14,905,366). Diluted net income per unit is calculated by dividing consolidated net income, plus interest expense relative to the debt that is being converted by the weighted average number of units used in the basic net income per unit calculation plus the number of units that would be issued assuming conversion of the exchangeable unsecured subordinated debentures into Trust Units of the Fund. For the purposes of the weighted average number of Trust Units calculation, Trust Units are determined to be outstanding from the date they are issued. Diluted income per Trust Unit is not calculated when the impact of the trust units issued on the exchange of the exchangeable unsecured subordinated debentures would be anti-dilutive.

NOTE 3 - FORMATION OF THE FUND

On April 8, 2004, the Fund issued 14,905,366 Trust Units in the Initial Offering at a price of \$10.00 per Unit for net proceeds of \$136,350 after deducting underwriters' fees of \$8,198 and estimated net expenses related to the offering of \$4,506. The net expenses have been adjusted to reflect the reimbursement by USEB of \$9,340 of costs associated with the equity financing by the Fund.

The Fund also received \$30,400 representing the proceeds of a new long-term debt facility ("Credit Facility") through Countryside Acquisition and paid deferred financing fees of \$675 related to the New Credit Facility. One of the Fund's subsidiaries entered into an interest rate swap agreement to fix the floating interest rate paid on these amounts borrowed under the Credit Facility for three years at a rate of 3.22% plus a stamping fee of 2%.

The net proceeds of the Initial Offering, and the Credit Facility, were used by the Fund, directly or indirectly through its wholly-owned subsidiaries, for the following purposes:

		Amount S
[i]	Acquisition of Countryside District Energy Holdings from U.S. Energy Systems, Inc. ("USEY")	17,635
[ii]	Repayment of existing long-term debt of a subsidiary of Countryside District Energy Holdings and associated interest rate swap	25,989
[iii]	Acquisition and amendment of existing loans to USEB and the funding of additional advances to USEB	107,000
[iv]	Acquisition of the USEB Royalty Interest [US \$6,000]	7,884
[v]	Funding of the Holdback account and funding of working capital	2,400
[vi]	Repayment of due to parent company	2,396
[vii]	Payment of loan origination fees on USEB loans	1,340
		164,644

The acquisition of Countryside District Energy Holdings, which includes the District Energy Systems, from USEY for approximately \$17,635 pursuant to a purchase and sale agreement is accounted for using the purchase method. The purchase price has been allocated as follows:

	Amount	
	S	
Working capital, including cash of \$1,394	2,393	
Capital assets	29,851	
Customer relationships	13,076	
Future incomé tax asset	224	
Other long-term liabilities	(4,682)	
Long-term debt	(23,227)	
Total	17,635	

Other long-term liabilities includes \$2,085 of fees associated with the early termination of the interest rate swap on the long-term debt that existed in a subsidiary of Countryside District Energy Holdings prior to the acquisition by the Fund. Subsequent to the acquisition of Countryside District Energy Holdings, the due to parent company balance of \$2,396 was repaid to USEY.

NOTE 4 - ACQUISITION OF RIPON POWER

The Fund's investment in Ripon Power, effective June 29, 2005 was made through its newly formed, wholly-owned subsidiary, Countryside US Holding. Financing for the transaction was provided through an amendment to the Fund's Credit Facility (see note 12). The acquisition was accounted for using the purchase method. The purchase price was satisfied through cash consideration of approximately \$44,000 [US \$35,800], plus approximately \$1,100 of transaction costs.

The purchase price has been allocated, in Canadian dollars, as follows:

	Amount
	. \$
Working capital, including cash of \$2,269	4,823
Property, plaint and equipment	46,933
Power purchase agreements	69,510
Other long term liability	(3,122)
long-term debt	(73,072)
Total	45,072

NOTE 5 - TRUST UNIT AND EXCHANGEABLE DEBENTURE OFFERING

Trust Unit and Exchangeable Debenture Offering (the "Offering")

On November 14, 2005, the Fund and Countryside Canada closed an offering of 4,720,000 trust units at \$9.35 per unit for gross proceeds of \$44,132 and \$64,180 [US \$55,000] aggregate principal amount of 6.25% U.S. dollar denominated exchangeable unsecured subordinated debentures ("Debentures"), due October 31, 2012 (the "Maturity Date"). The Trust Units were issued by the Fund and the Debentures were issued by Countryside Canada. Net proceeds of the Offering were approximately \$101,413 and were used to repay indebtedness under the Fund's revolving credit facility associated with the acquisition of Ripon Power, to acquire the long-term debt and working capital revolver of the Cogen Facilities and to pay transaction costs of the Offering with the excess remaining proceeds used for working capital purposes.

Debentures

Interest will be paid in US dollars, semi-annually in arrears on April 30 and October 31, in each year commencing on April 30, 2006. The first interest payment will include accrued and unpaid interest for the period from the closing of the Offering to April 30, 2006. The payment of Debenture principal and interest is subordinated in right of payment to the prior payment of all senior indebtedness of the Fund.

Each Debenture will be exchangeable for Units at the option of the holder at any time prior to the close of business on the earlier of the Maturity Date and the business day immediately preceding the date specified by Countryside Canada for redemption of the Debentures, at an exchange price of \$10.75 per Unit (the "Exchange Price") being a ratio of 109.4884 Units per one thousand US dollars in principal amount of Debentures, subject to adjustment in certain events in accordance with the trust indenture governing the terms of the Debentures. Holders exchanging their Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Debentures to the date of exchange. Notwithstanding the foregoing, no Debentures may be exchanged during the five business days preceding April 30 and October 31 in each year as the registers of the Debenture Trustee (as defined herein) will be closed during such periods.

The Debentures may not be redeemed by Countryside Canada on or prior to October 31, 2008, except in the event of the satisfaction of certain conditions after a Change of Control (as defined herein) has occurred. Thereafter, but prior to October 31, 2010, the Debentures may be redeemed, in whole or in part, at a price equal to the principal amount thereof plus accrued and unpaid interest on not more than 60 days' and not less than 30 days' prior notice, provided that the weighted average trading price of the Units on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given is not less than 125% of the Exchange Price. On or after October 31, 2010 and prior to the Maturity Date, the Debentures may be redeemed by Countryside Canada, in whole or in part, at a price equal to the principal amount thereof plus accrued and unpaid interest on not more than 60 days' and not less than 30 days' prior written notice.

Subject to regulatory approval, Countryside Canada may, at its option, elect to satisfy its obligation to pay the principal amount of the Debentures on redemption or at maturity through, in whole or in part, the delivery of freel-tradeable Units. The Fund will take all actions and do all things necessary or desirable to enable and permit Countryside Canada, in accordance with applicable law, to perform its obligations to deliver the requisite number of Units to the extent holders exercise their exchange right.

The Fund performed a valuation of the embedded holder option on the Debentures and determined that its value on November 14, 2005 was \$1,715. Such portion of the value of the Debentures has been recorded as a component of unitholders' equity. The liability component of the Debentures will be accreted to the face value of the Debentures over the term to maturity and accretion for the period will be included in interest expense in the consolidated statements of income (for the year ended December 31, 2005 - \$24).

NOTE 6 - INVENTORIES

Inventories consist of the following:

	December 31, 2005	December 31, 2004	
	<u> </u>	\$	
Spare parts	822	778	
Fuel	488	276	
	1,310	1,054	

NOTE 7 - LOANS RECEIVABLE FROM U.S. ENERGY BIOGAS CORP.

The interest rate on the USEB Loans is 11.0% per annum with a maturity date of April 8, 2019, subject to mandatory prepayment provisions and prepayment at the option of the lender after 10 years. The USEB Loans are denominated in Canadian dollars and principal and interest is paid monthly. Approximately 56% of the aggregate principal amount of the USEB Loans will amortize over the term of the USEB Loans, gradually increasing from 1.6% of the aggregate principal amount in the first year to 7.3% in the 15th year. The USEB Loans are collateralized by all the assets of USEB.

Principal repayments over the next five years and thereafter are as follows:

	Principal S
	<u> </u>
2006	2,040
2007	2,276
2008	2,539
2009	2,833
2010	3,161
Thereafter	91,112
	103,961
Less current portion	2,040
Long term portion	101,921

NOTE 8 - ROYALTY INTEREST IN U.S. ENERGY BIOGAS CORP.

The Fund, through Countryside Canada, acquired a convertible royalty interest in USEB for \$7,884 [US \$6,000] at closing of the Initial Offering. For each fiscal quarter prior to that in which the USEB Royalty Interest becomes convertible, the amount of the royalty payable to Countryside Canada will be 7% of USEB Distributable Cash Flow plus an additional percentage of USEB Distributable Cash Flow equal to 1.8% of USEB Revenues (both as defined in the USEB Royalty Agreement). The royalty payment is subject to a distribution cap such that no royalties may be paid unless, at the time of such payment, 104.09% of such amount is paid to holders of the USEB common stock, which are currently USEY and Cinergy Energy Solutions, Inc. ("Cinergy").

After the USEB Royalty Interest becomes convertible, but remains unconverted. Countryside Canada will be entitled to receive royalties equal to 49% of the USEB Distributable Cash Flow. The USEB Royalty Interest is convertible at any time in the event of the prepayment in full of the USEB Loans, or on or after the 20th anniversary of the closing of the Initial Offering into non-voting common shares of USEB, representing 49% of the number of common shares of USEB outstanding at the time of conversion. Upon conversion of the USEB Royalty Interest, Countryside Canada's right to receive royalties will terminate.

Amounts owning under the USEB Royalty are payable quarterly, in arrears.

NOTE 9 - OTHER ASSETS

Other assets consist of the following:

	December 31, 2005	December 31, 2004	
	\$	\$	
Deferred financing fees, net of accumulated amortization of \$215 (2004 - \$169)	4,671	506	
Loan origination fees, net of accumulated amortization of \$156 (2004 - \$67)	1,184	1,273	
Long-term receivable	571	202	
Fair value of foreign exchange option contract	215	-	
Fair value of interest rate swap and other [note 12]	253	1	
	6,894	1,982	

Notes to Consolidated Financial Statements - for the year ended December 31, 2005
[all amounts in thousands of dollars except per Trust Unit amounts].

Deferred financing fees related to the original Credit Facility of \$415 were written off in the second quarter of 2005 because the Amended Credit Facility was entered into in order to finance the acquisition of Ripon Power [note 12].

Approximately \$3,922 in costs related to the Debentures were deferred and will be amortized over the term of the Debentures. These have been included in deferred charges commencing in the fourth quarter of 2005.

NOTE 10 - PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	December 31, 2005 Dec		December 31, 2004	
	Cost	Accumulated depreciation	Cost	Accumulated depreciation
	\$	<u> </u>	\$	\$
land	2,898	-	339	-
Buildings	3,149	187	2,648	<i>7</i> 6
Equipment				
Plant and distribution	70,431	4,173	27,269	819
Computers	95	26	65	32
Office	38	8	87	4
Vehicles	169	49	102	47
Construction in process	139	-	904	-
Equipment under capital lease	352	21	236	9
	77,271	4,464	31,650	987
Net book value		72,807		30,663

NOTE 11 - OTHER INTANGIBLES

Other intangibles consist of the following:

	December 31, 2005	December 31, 2004 \$
	\$	
Customer relationships, net of accumulated amortization of \$1,090 (2004 - \$467)	11,986	12,609
Power purchase agreements, net of accumulated amortization of \$2,663	63,092	-
	75,078	12,609

Customer relationships relate to the purchase of the District Energy Systems. Power purchase agreements were acquired as part of the purchase of the Ripon Power assets.

NOTE 12 - LONG-TERM DEBT

On June 27, 2005. Countryside Acquisition amended its revolving credit facility ("Amended Credit Facility"), with Toronto Dominion Bank as sole lender (a Canadian chartered bank), to increase the amount of the commitment in order to facilitate the acquisition of Ripon Power. On August 12, 2005, the Amended Credit Facility was subsequently syndicated to include Royal Bank of Canada and Canadian Imperial Bank of Commerce as lenders. The Amended Credit Facility provides up to a \$78,000 revolving credit commitment with no principal repayment until its maturity on June 27, 2008. The Amended Credit Facility also allows for a swing line of credit in the amount of \$2,000 and has the same three year maturity as the Amended Credit Facility. Advances under the Amended Credit Facility are available to be drawn in either Canadian or U.S. dollars. The interest rate on Canadian dollar advances will be based on either Canadian prime rate or bankers' acceptances and U.S. dollar advances will be based on either U.S. base rate or London

Interbank Offered Rate ("LIBOR"). The applicable margin or stamping fee on the respective base rate will be tied to the leverage ratio of Countryside Acquisition's parent, Countryside Canada calculated at the end of each calendar quarter. The stamping fee may change in the future if the leverage ratio changes, which could result in an increase or decrease in the effective rate of interest paid on the long-term debt. A standby fee based on the actual leverage ratio of Countryside Canada is charged on the unutilized portion of the Amended Credit Facility and the swing line of credit. The Amended Credit Facility was further amended on November 14, 2005 to accommodate the Offering. The Amended Credit Facility further allows for letters of credit to be issued, which if issued reduces the amount of available revolving credit commitment accordingly. The fee paid on the letter of credit is also tied to the leverage ratio of the Borrower's payout.

As at December 31, 2005, \$47,500 was drawn under the terms of the Amended Credit Facility in the form of bankers' acceptances at 3.53%, plus a stamping fee of 2.375%. Of the \$2,000 swing line of credit, \$1,615 was drawn at December 31, 2005 at Canadian prime rate of 5.0%, plus a spread of 1.375%. A \$3,489 [US \$3,000] letter of credit was issued on November 14, 2005 under the Amended Credit Facility and will expire on November 14, 2006 unless extended. The letter of credit replaces a letter of credit issued under the Ripon Credit Facility (defined herein) and essentially provided credit support to the Cogen Facilities' fuel supplier for natural gas purchases. The letter of credit is currently subject to a fee of 2.375% per annum. At December 31, 2005, \$27,396 was not drawn on the Amended Credit Facility, including \$385 that was not drawn on the swing line of credit. Both undrawn amount is subject to a standby fee of 0.60% per annum. The effective rate of interest for amounts drawn under the Amended Credit Facility is the funded base rate plus the stamping fee, increased or decreased by any amounts due or owed, respectively, by the Borrower under the interest rate swap as described below. For a portion of the quarter ended December 31, 2005, the Fund chose to borrow at Canadian prime rate in anticipation of the Offering [note 5].

As of April 8, 2004, the Borrower entered into an interest rate swap agreement to fix the interest rate paid on \$30,000 of its' long-term debt at a rate of 3.22%, which is based on bankers acceptances. On December 6, 2005, this swap was renegotiated which resulted in a new swap agreement with a notional amount of \$47,000 and a fixed rate of 3.87%. The swap matures on June 27, 2008 and payments are due every three months.

As at December 31, 2005, the fair value of the interest rate swap agreement was \$253 favourable and has been included with other assets on the consolidated balance sheets.

Amounts drawn under the Amended Credit Facility are principally collateralized by (i) a general security agreement and securities pledge from Countryside Acquisition, (ii) a guarantee, general security pledge and assignment of insurance proceeds by Countryside District Energy Holdings Corp. and by Countryside District Energy Corp. and (iii) a guarantee and general security agreement by Countryside Canada. The Countryside US Holding and Ripon Power assets are excluded from the collateral pool under the Amended Credit Facility.

At December 31, 2005, the fair value of the amount drawn on the Amended Credit Facility approximated its carrying value.

Ripon Credit Facility

Ripon Cogen, the operating subsidiary of Ripon Power, entered into a credit facility dated as of March 24, 2005 among a syndicate of U.S. Banks, led by Union Bank of California, N.A. ("UBOC"), in its capacity as administrative agent, collateral agent and issuing bank on behalf of the lenders ("Ripon Credit Facility"). The Ripon Credit Facility and working capital revolver was acquired by Countryside US Holding at the closing of the Offering with a portion of the net proceeds of the Offering. Prior to November 14, 2005, the Ripon Credit Facility included a \$69,198 [US \$59,500] term loan facility maturing on April 25, 2018, a \$5,815 [US \$5,000] debt service reserve letter of credit expiring on March 24, 2015), a \$3,489 [US \$3,000] letter of credit issued for benefit of a fuel supplier with an expiration of July 10, 2006, and a \$2,326 [US \$2,000] working capital revolver maturing on March 24, 2008.

The term loan facility was available to be drawn in U.S. dollars, and the interest rate was based either on the U.S. prime, or LIBOR rate, plus an applicable margin which escalated throughout the loan term.

The debt service reserve and the fuel supplier letters of credit were subject to fees on the issued amount, equal to the then applicable margin of the term loan facility.

As of March 30, 2005, Ripon Cogen entered into an interest rate swap agreement with UBOC to fix the interest rate paid on the fully drawn balance of the term loan facility at 4.939% per annum. The applicable margin in effect during the period from the date of the Fund's acquisition of Ripon Power through the Ripon Credit Facility repayment date was 1.50%. The swap maturity coincided with the maturity of the Ripon Credit Facility on April 25, 2018. The notional amount of the swap was initially US\$59,500 and was adjusted each quarter to match the amortization of the term loan facility.

On October 25, 2005, the interest rate swap agreement was terminated at a cost to the Fund of \$496 [US \$425].

NOTE 13 - FUTURE INCOME TAX LIABILITY

The income tax expense consists of the following:

		For the period from February 16, 2004 to December 31, 2004	
	<u> </u>	\$	
Current	22	10	
Future	1,309	506	
Provision for income taxes	1,331	516	

The future income tax liability consists of the following:

	December 31,2005	December 31,2004	
	\$	\$	
Future income tax asset			
Losses available for carry forward	3,300	3,302	
Property, plant and equipment	924	306	
Loss on interest rate swap	•	18	
Future income tax liability			
Customer relationships	(4,395)	(3,908)	
Gain on interest rate swap	(91)	-	
Difference between tax and book income of U.S. subsidiary	(1,329)	<u>.</u>	
Net future income tax liability	(1,591)	(282)	

The provision for income taxes differs from the expense that would be obtained by applying Canadian statutory tax rates as a result of the following:

	For the year ended December 31, 2005	For the period from February 16, 2004 to December 31, 2004
	\$	\$
Consolidated income before provision for income taxes	14,492	8,081
Income not subject to tax accounting	13,750	10,114
loss before income taxes	742	(2,033)
Combined federal and provincial income taxes at statutory rate of 37% [2004 - 37%]	277	(751)
Manufacturing and processing deduction	(42)	(132)
Change in future tax rates	45	-
losses not benefited	2,550	1,389
Losses not previously recognized	(1,521)	
Other	22	10
Provision for income taxes	1,331	516

At December 31, 2005, the Fund has non-capital losses available for carry forward of approximately \$29,859 to reduce future taxable income. The tax benefit associated with the District Energy Systems in respect of approximately \$20,859 of these losses has not been recognized in the accounts of the Fund as at December 31, 2005. The majority of these losses expire starting in the year 2006.

Notes to Consolidated Financial Statements - for the year ended December 31, 2005 [all amounts in thousands of dollars except per Trust Unit amounts].

The Fund loaned \$107,000 to USEB in 2004, and loaned Countryside US Holding \$60,638 [US \$52,139] by way of an intercompany note during 2005. The Fund has been advised by US tax counsel that interest paid by USEB on the USEB Loans should be deductible by USEB and that interest paid by Countryside US Holding on the intercompany note should be deductible by Countryside US Holding for US federal income tax purposes. The interest on the USEB loans is not subject to any US withholding tax, however, the Countryside US Holding note is subject to US withholding tax at 10%. The consolidated financial statements of the Fund reflect this opinion. However, there is a risk that the Internal Revenue Service ("IRS") could successfully challenge such treatment, resulting in some or all of the interest on the USEB Loans being non-deductible by USEB and/or also resulting in some or all of the interest on the intercompany note to Countryside US Holding being non-deductible by Countryside US Holding and some or all of such interest being subject to US withholding tax at rates of 10% to 30%. As a result, the amount of funds available for distribution to Unitholders could be reduced.

Although management believes that it is unlikely that the IRS would be successful, the application of withholding tax could result in the Fund incurring a liability for taxes. If the Fund were to become liable to pay or remit any withholding tax, other than a withholding tax arising from a disposition of the USEB Loans by the Fund, USEB will be required to increase the amount of interest paid to the Fund with respect to the USEB Loans such that, after such withholding tax, the Fund will receive the same amount that it would have received in the absence of such withholding tax.

In addition to the foregoing, and in common with other complex international business structures, the Fund is subject to various additional uncertainties concerning the interpretation and application of Canadian and U.S. tax laws. If tax authorities disagreed with the Fund's application of tax laws, the Fund's profitability and cash flows could be adversely affected.

NOTE 14 - TRUST UNITS

The Declaration of Trust provides that an unlimited number of Trust Units may be issued. Each trust unit represents an equal undivided beneficial interest in any distribution from the Fund and in any net assets of the Fund in the event of termination or wind-up. All trust units are of the same class with equal rights and privileges.

The trust units are redeemable at the holder's option at an amount equal to the lesser of: (a) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10-trading day period ending on the date on which the Trust Units were surrendered for redemption (the "Redemption Date"); and (b) 100% of the "closing market price" on the principal market on which the Trust Units are quoted for trading on the Redemption Date. Redemptions are subject to a maximum of \$50 in cash redemptions in any particular month.

On November 14, 2005, the Fund closed an offering of 4,720,000 Trust Units and \$63,965 [US \$55,000] aggregate principal amount of 6.25% Debentures [note 5]. The Trust Unit portion of the offering resulted in net proceeds of approximately \$41,155 after the deduction of \$2,207 in commissions and \$770 in related transaction costs.

	Number of Units	Amount	
		\$	
Balances at April 8, 2004 and December 31, 2004	14,905,366	136,350	
Issued trust units at November 14, 2005	4,720,000	44,132	
Issue costs		(2,977)	
Balance at December 31, 2005	19,625,366	177,505	

The reconciliation of the denominator in calculating diluted per unit amounts is as follows:

	For the year ended December 31,2005	For the period from April 8 to December 31, 2004
Weighted average number of units outstanding, basic Effect of dilutive securities:	15,513,147	14,905,366
Exchangeable unsecured subordinated debentures	<i>77</i> 5,418	-
Weighted average number of units outstanding, diluted	16,288,565	14,905,366

NOTE 15 - CONCENTRATION OF CUSTOMER CREDIT RISK

Derivative Financial Instruments

In addition to the interest rate swap contracts (note 12), the Fund has purchased thirty-six consecutive monthly "knockout" call option contracts, commencing in January 2006, which have an exercise price of US \$0.89 per Canadian dollar, at a cost of \$219 and a notional amount of approximately US\$5,300. To the extent that the US/Canadian dollar exchange rate reaches \$0.84 (the "knockout price") at any time while the option contracts are still in effect, the remaining unexpired monthly call option contracts will immediately expire and be automatically replaced with forward foreign exchange contracts with the same scheduled monthly Canadian dollar amounts at the exchange rate equal to the knockout price.

Concentration of Credit Risk

The Fund is dependent upon the operations and assets of USEB through the USEB Loans and the USEB Royalty Interest.

Each of the Cogen Facilities has one primary utility customer as well as one industrial customer to which it provides steam, under long-term contract. The Fund's credit risk exposure in the event of non-performance by its customers is limited to the face value of the receivables. No collateral is required on these receivables.

Electricity sale pursuant to the PPA with Southern California Edison ("SCE") and Facific Gas & Electric ("PG&E") accounted for 31% and 17%, respectively, of revenue for the year ended December 31, 2005. Approximately 51% of the year end accounts receivable balance was due from SCE relating to electricity sales.

NOTE 16 - COMMITMENTS AND CONTINGENCIES

Commitments

As of April 8, 2004, Countryside Canada delivered a performance guarantee in favour of WPS Energy Services, Inc. ("WPS") respecting Countryside District Energy Holding Corp.'s future obligations to WPS under the Master Natural Gas Sales and Purchase Agreement dated December 1, 2001 (the "Purchase Agreement"). All natural gas utilized by the London System (a division of Countryside District Energy Corp.) is purchased under the Purchase Agreement with WPS. Such guarantee is limited to an aggregate amount of \$1,000 and to liabilities incurred prior to December 31, 2005 or such earlier date designated by Countryside Canada on 10 days notice to WPS. The Fund renewed the guarantee, effective January 1, 2006 to an aggregate amount of \$1,200, covering the period up to December 31, 2008.

The Cogen Facilities are comprised of the "Ripon Facility" and the "San Gabriel Facility". Each facility has a gas turbine lease agreement with a third party, to have turbines available for their use during the year in the case of malfunction of the existing equipment. The annual cost of these leases is approximately \$343 [US \$295]. The leases expire in August 2006 and July 2007, respectively. Both leases are subject to an annual escalation amount based upon an inflation factor.

The Cogen Facilities have two power turbine lease agreements with a third party, one for each facility, to have a rotor, turbine casing and transition duct available for their use during the year in the case of malfunction of the existing equipment. The annual cost of each of these leases is approximately \$58 [US \$50]. Both leases expire in March 2009.

Under the Cogen Facilities' fuel purchase agreements with British Petroleum ("BP"), each facility is required to purchase 10,000 Million British Thermal Units ("MMBtu's") of natural gas each day. This purchase commitment is effective for both facilities through the life of agreements, which expire on June 30, 2006. The price of fuel for the Ripon Facility is fixed at \$6.17 [US \$5.31] per MMBtu under its fuel purchase agreement. Accordingly, the Ripon Facility's approximate minimum future fuel commitments subsequent to December 31, 2005 are \$11,168 [US \$9,611] for 2006. The price of fuel for the San Gabriel Facility resets monthly at current market prices. As such, the San Gabriel Facility's total fuel cost commitments through June 30, 2006 are not reasonably determinable. The San Gabriel Facility's effective price of fuel was \$9.76 [US \$8.39] per MMBtu for December 2005.

Operation and maintenance agreements have been entered into with North American Energy Services Company ("NAES") for the operation and maintenance of each of the Cogen Facilities. The agreements cover the operation of the two plant facilities including administration of all payroll and benefits for plant staff, plant operations and compliance and facility level accounting. Annual fees for each of these agreements are \$198 [US \$170] plus an incentive payment, which is a maximum of \$93 [US \$80] per year. These agreements expire in 2011.

Commitments under other operating leases at December 31, 2005 are: 2007 - \$428; 2008 - \$406; 2009 - \$284; 2010 - \$246; 2011 and thereafter - \$417.

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Contingencies

A proceeding is currently pending before the California Public Utility Commission ("CPUC"), in which the CPUC is considering whether to apply a March 2001 ruling which decreased "Short Run Avoided Cost" or "SRAC" levels retroactively for the period from December 2000 to March 2001. Such a ruling could, in theory, apply to many Qualifying Facilities ("QF's") in California, including the Cogen Facilities and may lead utilities to seek refunds or offsets from the QF's which sold the utilities' power during such 4 month period. While management believes that such a result is unlikely, the outcome of such a regulatory proceeding cannot be predicted with certainty. Even in the event of an adverse result, management believes Ripon would have several meritorious legal defenses under federal and state law which should protect Ripon from any material adverse impact. However, there is no assurance that Ripon would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal or otherwise enjoined, QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could materially and adversely affect the Cogen Facilities' ability to generate distributable cash.

In December 2005, two shareholders of USEY commenced an action in the Delaware Court of Chancery against USEY, the current directors of USEY, certain former directors and officers of USEY, the Fund and Countryside U.S. Power alleging, among other things, that the defendants violated the Delaware General Corporations Law and fiduciary duties to USEY shareholders in connection with USEY's sale of indirect ownership of the District Energy Systems to the Fund and the consummation of the April 2004 USEB Loan transaction. The Plaintiffs seek damages and equitable relief. The Fund and Countryside U.S. Power believe that the claims alleged against them are without merit and have moved to dismiss the action on, among other grounds, failure to state cause of action, unreasonable delay and lack of personal jurisdiction. Such motion is pending. In the event the suit is neither resolved nor dismissed, the Fund and Countryside U.S. Power intends to defend the suit vigorously. Although the likelihood of an adverse judgment cannot be assessed at this early stage, the Fund and Countryside U.S. Power do not believe it is likely that the litigation will have a material adverse affect on the Fund or Countryside U.S. Power.

NOTE 17 - DEVELOPMENT AGREEMENT WITH CINERGY AND JSEY

As of April 8, 2004 Countryside U.S. Power entered into a Development Agreement with an indirect subsidiary of Cinergy and USEY under which, subject to its terms and conditions, the Cinergy subsidiary and USEY may contribute their experience and financial resources to the acquisition, development, improvement and operation of energy projects that they choose to pursue and that will meet the Fund's investment and growth objectives. Countryside U.S. Power provides investment analysis and evaluation services on behalf of all parties to the agreement. In consideration for these services, Countryside U.S. Power is to be paid an annual fee of approximately \$512 [US \$440] from an indirect subsidiary of Cinergy and USEY. Commencing in May 2005, USEY stopped making payments with respect to its portion of the fees. Countryside U.S. Power and USEY are in discussions concerning USEY's obligations under the Development Agreement.

The Development Agreement has an initial term of five years and will be automatically renewed for an additional five year term unless terminated by any party.

NOTE 18 - DISTRIBUTIONS TO UNITHOLDERS

Distributions totaling \$1.0285 per Trust Unit (2004 - \$0.7488) being aggregate distributions of \$16,145 (2004 - \$11,161) were declared. For income tax purposes \$5,531 (2004 - \$2,519) of the distributions are treated as a return of capital.

Distributions are declared for unitholders of record on the last business day of a calendar month to receive distributions on or about the 30th day of the following month. Holders of units who are non-residents of Canada will be required to pay all applicable withholding taxes payable in respect of any distributions by the Fund.

NOTE 19 - SEGMENTED DISCLOSURE

The Fund owns and operates the District Energy Systems and the Cogen Facilities. It also had a loan to, and a convertible royalty interest in, USEB, which is included with the Fund's corporate administrative operations for reporting purposes. These three assets represented the Fund's reportable segments at December 31, 2005.

The Fund analyzes the performance of its three operating segments based on earnings before interest, income taxes, unrealized and realized interest rate swap and unrealized foreign exchange gains and losses, and depreciation and amortization ("Adjusted EBITDA"). Adjusted EBITDA is not a standard measure under Canadian GAAP and hence may not be comparable to similar EBITDA information presented by other funds.

The Cogen Facilities were purchased on June 29, 2005, thus the results in the year ended December 31, 2005 represent six months of operations. Similarly, the operating results of the District Energy Systems are reflected from the date they were purchased by the Fund on April 8, 2004 in the table entitled 267 days ended December 31, 2004.

Year Ended December 31, 2005

	District Energy	Cogen Facilities	Corporate and Other	Total
Revenues				
Energy	17,932	34,891		52,823
Other	1,894	49	12,395	14,338
Oniei	19,826	34,940	12,395	67,161
Expenses	· · · · · · · · · · · · · · · · · · ·	· · · · · · · · · · · · · · · · · · ·		·
Fuel, operating and maintenance	12,894	22,004	-	34,898
General and administration	1,046	754	5,953	<i>7,75</i> 3
	13,940	22,758	5,953	42,651
Adjusted EBITDA	5,886	12,182	6,442	24,510
Depreciation of property, plant & equipment				3,363
Other asset amortization				4,698
Operating income		,		16,449
Capital expenditures	834		21	855
267 Days Ended December 31, 2004				
	District Energy	Cogen Facilities	Corporate and Other	Total
Revenues				
Energy	10,466		-	10,466
Other	1,278	_	9,392	10,670
One	11,744		9,392	21,136
Expenses			.,,,,,,,	
Fuel, operating and maintenance	7,775	-	_	7,775
General and administration	758		1,295	2,053
	8,533	-	1,295	9,828
Adjusted EBITDA	3,211		8,097	11,308
Depreciation of property, plant & equipment				988
Other asset amortization				998
Operating income				9,322
Capital expenditures	1,701	-	98	1, <i>7</i> 99
			December 31, 2005	December 31, 2004
			\$	S S
Total assets		· · · · · · · · · · · · · · · · · · ·	<u> </u>	<u> </u>
District Energy			35,899	31 <i>,7</i> 56
Cogen Facilities			124,041	-
Corporate and Other			131,867	134,361
			291,807	166,117
			December 31, 2005	December 31, 2004
			\$	\$
Total other intangibles, net				
District Energy			-	-
Cogen Facilities			63,092	
Corporate and Other			11,986	12,609
			, -	

All assets, liabilities and revenues located in Canada relate to the District Energy Systems. All assets, liabilities and revenues located in the United States relate to Ripon Power, Countryside US Holding or Countryside U.S. Power, as well as the USEB Loans, USEB Royalty Interest, the income from the USEB Royalty Interest and the development fee revenue, which are earned from entities based in the United States.

Capital expenditures included in the table above include both non-expansionary expenditures for regular operations as well as capital expenditures for improvement or growth projects.

NOTE 20 - RELATED PARTY TRANSACTIONS

Independence Power LLC

On June 29, 2005, Countryside US Holding, an indirect subsidiary of the Fund, paid \$437 to Independence Power LLC ("Independence") in consideration for services performed in the normal course of development operations by Independence for Countryside US Holding in connection with the origination and structuring of the acquisition of Ripon Power LLC. This amount was recorded as part of general and administration expenses. Independence is controlled by members of senior management of the Fund who serve as officers and directors of certain Fund subsidiaries including Countryside US Holding and Countryside U.S. Power. Independence changed its name to Countryside Ventures LLC ("Countryside Ventures") on September 19, 2005.

Management Agreement

On September 23, 2005, Countryside US Holding and Countryside Canada entered into a management agreement ("Management Agreement") with Countryside Ventures (the "Manager"). Under the terms of the Management Agreement, effective November 1, 2005, Countryside Ventures commenced, providing management and administrative services to Countryside Canada and Countryside US Holding as well as new growth opportunities under long-term agreements. Effective November 1, 2005, Countryside Ventures commenced employing the Fund's current executive management team on a full time basis as well as its administrative and development staff. The Fund, through Countryside US and Countryside Canada, has a right of first offer on all investment opportunities developed by Countryside Ventures that meet the Fund's investment criteria. In consideration for providing the management and administrative services under the Management Agreement, the Manager shall be entitled to reimbursement from Countryside US Holding and, to the extent the Manager provides services to Countryside Canada at its request, Countryside Canada, of all costs and expenses reasonably incurred by the Manager and its affiliates in carrying out the services described above. During 2005, a total of \$805 was paid to Countryside Ventures pursuant to the Management Agreement.

Administration Agreement

On September 26, 2005 the Fund and Countryside U.S. Power entered into a Management and Administration Agreement ("Administration Agreement") with Countryside Canada Ventures Inc. ("Countryside Ventures Canada"), which is a wholly owned subsidiary of Countryside Ventures. Under the Administration Agreement, which was effective November 1, 2005, Countryside Ventures Canada commenced providing management and administrative services to the Fund and Countryside Canada. In carrying out the services described above, Countryside Ventures Canada and its affiliates will be entitled to reimbursement from the Fund and Countryside Canada of all costs and expenses incurred in connection therewith. During 2005, a total of nil was paid to Countryside Ventures Canada.

Operating Agreement

In conjunction with the Management Agreement, Countryside US Holding and Countryside Ventures entered into an Operating Agreement on November 3, 2005 respecting Ripon Power which will be effective as of July 1, 2005. This agreement will implement for the Ripon Power acquisition, the long-term incentive plan provided for in the Management Agreement. Under the terms of the Operating Agreement, Countryside US Holding will hold a preferred membership interest (the "Preferred Interest") entitling it to preferred distributions of "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Operating Agreement. Countryside US Holding and Countryside Ventures will, hold subordinate membership interests (the "Subordinate Interests") entitling them to residual distributions made to members, after distributions made in respect of the Preferred Interest, in a ratio of 75:25. Countryside Ventures' Subordinate Interest distribution is subject to downward adjustment and mutual exchange rights as provided in the Management Agreement. During 2005, a total of \$1,515 was paid to Countryside Ventures pursuant to the Operating Agreement related to its Subordinated Interests.

NOTE 21 - COMPARATIVE AMOUNTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the current year consolidated financial statements.

TRUSTEES AND THE MANAGEMENT

TRUSTEES AND DIRECTORS

V. Jomes Sardo

Chairman of Countryside Power Income

jamies R. Airderson

Trustee of Countryside Power Income Fund

Dr. Oskar Sigvelduson

Trustee of Countryside Power

Income Fund

James Speyer

Director of Countryside US Holding Corp.

MANAGEMENT

Göran Milinhod

President & Chief Executive Officer Countryside Ventures LLC

Edwara M. Campana

Executive Vice President & Chief Financial Officer
Countryside Ventures LLC

After Rushinan

Senior Vice President & General Counsel Countryside Ventures LLC

Perulante in Lucia

Vice President, Operations Countryside Ventures LLC

Nicolo Airmida d

Vice President, Finance & Administration Countryside Canada Ventures Inc.

UNITHOLDER information

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TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company P.O. Box 7010, Adelaide Street Postal Station Toronto, Ontario M5C 2W9

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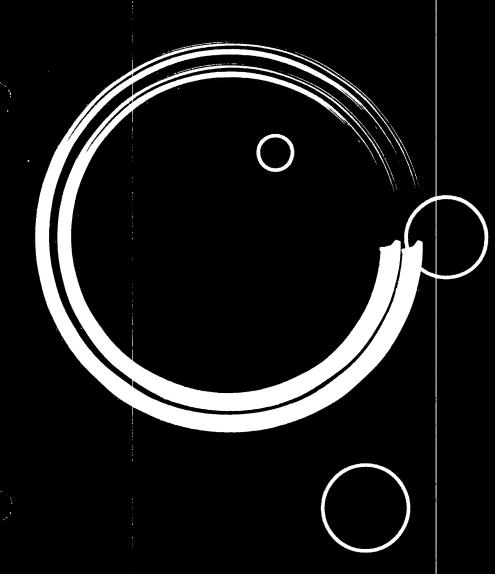
AUDITORS

Ernst & Young LLP 222 Bay Street, TD Centre Toronto, Ontario M5K 1J7 Countryside Power Income Fund trades on the Toronto Stock Exchange (TSX) under the symbol COU.UN.

Countryside Canada Power Inc.'s U.S. -dollar denominated exchangeable debentures trade on the TSX under the symbol CSD.DB.U.



2005 ANNUAL REPORT



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